Orbit

Volume 27 • Number 1 • 2007

Fruitful Results

How System 1* Software Pays for Itself

Inside this issue

- Case History: Rub Diagnosis Saves $7MM for Syncrude Canada
- Back to Basics: Beat Frequencies
- The Morton Effect: What Is It?
- First Look: Four New Products
- Case History: Monitoring Offshore Facilities at Norway's Hydro Oil & Energy

Orbit

A Technical Publication for Advancing the Practice of Operating Asset Condition Monitoring, Diagnostics, and Performance Optimization

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EDITOR'S NOTE

Fun with Photos

Choosing the cover artwork for this issue of ORBIT was a lot of fun. Perhaps it's because I grew up near fruit orchards (pears...not apples) and the image we finally settled on brought back pleasant memories of pastoral settings. More than that, however, was the challenge of finding an image that conveyed "payback," but without the negative implications that the word denotes today—namely, TV thugs who vow to "pay back" in the form of black eyes, broken bones, or worse. Regardless, the end result is clearly a departure from the photos of industrial plants that graced our covers for many years. Never would I have guessed that someone could conceivably mistake a journal on condition monitoring and equipment health with a journal on agriculture.

This issue's cover story addresses a long-standing request from our customers. Namely, to help articulate the ways in which condition monitoring software can pay for itself. If you have ever sat down to generate a financial justification and wished you had assistance with the numerous benefits of condition monitoring in general, and condition monitoring software in particular, you'll find this article by GE's Jeff Sipek to be highly relevant.

In support of this issue's theme, we've also taken special care to choose case histories and "Synopses of Savings" entries that pertain directly to System 1 software. Like our readers who tell me that case histories are among their favorite content in ORBIT, I always enjoy our case histories as well, both for the technical content (I always learn something new) and for the validation that our tools continue to provide a high level of customer value.

Space doesn't permit me to mention every article in this issue, but I encourage you to peruse the Table of Contents. There's a mix of back-to-basics, applications, new product introductions, case histories, and announcements regarding our activities around the world. As always, I love to hear directly from our readers to ensure we are meeting your needs and providing relevant content in the pages of this journal. Drop me a line at orbit@ge.com or, if you prefer, provide your feedback in our reader survey at www.ge-energy.com/orbitsurvey.

Steve Sabin
Editor

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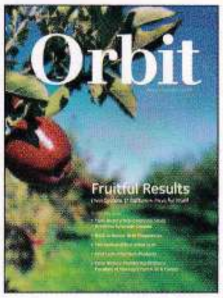

Cover Story

4 Fruitful Results: How System 1* Software Pays for Itself

Case Histories

12 Synopsis of Savings

24 Hydro Oil & Energy's New North Sea Operations Center Cuts Production Losses

34 Diagnosing and Correcting a Rub in a Mechanical Drive Steam Turbine at Syncrude Canada

New Product Showcase

16 An All-New Version of the ProxPac* Probe Housing Assembly

18 ADRE* Transducer Power Supply Module

19 TK-3 Proximity System Test Kit

20 New Stand-Alone Tach100 Tachometer Now Available

Recip Tips

22 Mechanical Protection for Cylinder Pressure Transducers

Back to Basics

62 Beat Frequencies

Announcements

15 Give us your e-mail, get e-ORBIT!

23 2007 Users Conferences

33 Minden Facility Achieves VPP Recertification

65 Customer Application Centers

From the Desk Of

14 Taking Excellent Care of Our Customers

60 MDS – At Your Service

Applications

44 The Morton Effect and Light Rubs in Rotating Machinery

52 Considerations When Using Extended Field Wiring Lengths With Bently Nevada Transducers

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Fruitful Results:

How System 1* Software Pays for Itself

With online and offline condition monitoring software steadily gaining in acceptance over the last 25 years, it is very rare today to encounter rotating machinery, reliability, and maintenance professionals that don't instinctively understand the needs for these tools. However, articulating the value in a manner that allows a compelling business case to be constructed requires more than just a list of features, functions, and technical specifications.

In my job as product line leader for System 1 software, I meet with our users and our sales professionals regularly. Over time, you begin to identify a number of recurring strategies that have been employed to help build the business case for condition monitoring software. Knowing for quite some time that this issue of ORBIT was going to be devoted to several articles on System 1 software, I contemplated what I could say

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that would be most beneficial to our readers. While the temptation was to talk about technology, features, and functions, it occurred to me that perhaps the most valuable thing I could do would be to provide a look at the ways users have told us they receive value from their condition monitoring software. To that end, I've summarized 16 of the most common and effective strategies that users have used to build the business case for condition monitoring software in their own organizations, showing that it isn't a cost—it's an investment.

#1 – Think Safety and Environment

While justifications based on reductions in maintenance costs and unplanned downtime are certainly valid, don't forget about safety and environmental issues. For example, many plants have relied either partially or completely on financial justifications for their condition monitoring systems that emphasize the ability to detect seal failures that can result in fires or toxic substance leaks into the atmosphere. These "events" can be enormously costly, both in terms of direct financial impact and the harder-to-measure (but nevertheless important) indirect impact of negative publicity. Finally, although personnel injuries or fatalities are rare due to machinery failures, this is still a very real concern. Thrown blades, thrust bearing failures, and overspeed events are just three examples that could be cited where people have been injured or killed. Condition monitoring systems can identify problems in running machinery at a distance. They can also provide early warning of developing problems before those problems progress to catastrophic failures.

#2 – Think Performance

Rotating machinery engineers and mechanical maintenance personnel tend to think in terms of vibration diagnostics and mechanical condition. It's important, but it can sometimes be difficult to make the business case because it often relies on "negative events" (mechanical failures) as the basis for justification—and failures, as we all know, are by their nature somewhat unpredictable. People are understandably skeptical about what "might" happen in the future versus things that are more certain. But System 1 software is not limited to just mechanical condition. It is also capable of sophisticated thermodynamic performance monitoring. It is typically much easier to develop a financial "payback" estimate for things that relate directly to machinery efficiency, throughput, and fuel costs because a literal "per hour" or "per day" business case can often be developed showing efficiency and fuel cost savings. The incremental cost to add mechanical condition tools to the already-present thermodynamic performance tools is quite modest. Thus, a strategy to "sell" System 1 to management based on its thermodynamic performance monitoring capabilities, rather than strictly its mechanical condition capabilities, can be quite effective.

[Editor's Note: For an example of how one customer is using the thermodynamic performance aspects of System 1, please see the Case History on page 24 of this issue.]

#3 – Tap Into Your Plant's Operations Budget

Increasingly, we hear users lament that their maintenance budgets are not just tight—they're sealed. But that's rarely the case for the plant's operations budget. Many of those in Maintenance are telling their counterparts in Operations, "If you want me to support you properly and keep your machinery running, you need to equip me with the right tools." If your maintenance budget has no room for the tools to do your job, consider going to Operations. In many cases, they understand the value of this software because they understand the implications of unplanned downtime and the importance of making real time decisions that impact the production of the plant.

#4 - Think Reliability

Condition monitoring software is one of the single most important tools for improving plant reliability. While an average plant spends between 5% and 8% of replacement asset value per year on maintenance, best-in-class reliability performers spend less than half that amount—only 2% to 3%. These companies are spending less than half on maintenance than their competitors, yet outperforming them in nearly every meaningful metric.

#5 – Think Emissions

Closely tied into tip #2, it is becoming increasingly common to see the emergence of taxes on emissions such as CO_2 and NO_x. For example, the CO_2 taxes on a typical gas turbine running on offshore platforms in the Norwegian North Sea are in excess of 2.5MM USD per year, and new NO_x taxes have recently been introduced as well. Even a modest improvement in efficiency of 1-2% can have a direct affect on those emissions and help reduce taxes. And as noted previously, once a System 1 installation is in place, the incremental costs to add mechanical condition monitoring to the thermodynamic performance monitoring capabilities are quite modest.

#6 – Use Historical Records

Chances are, your plant has kept records on the number of forced outages, machinery failures, and other "events" over the years. Use this data to make your business case. While knowing exactly when the next failure is going to occur is never absolutely certain, a data-driven, objective business case that quantifies the number of failures, the amount of the downtime, and the financial costs is always preferred because it establishes a baseline against which improvement can be measured.

#7 – Avoid Sweeping Generalizations

Words like "eliminate," "never," and "always" are sometimes appropriate, but be realistic. Don't over-promise and under-deliver. It isn't necessary to say things like "this system will eliminate unplanned outages" when the reality may instead be that it can reduce their duration when they do occur. Many of our users tell us repeatedly that the value of their systems is that when a machinery problem occurs, they know about the condition and can plan accordingly. Often, they are able to trim a day or more off the downtime. Instead of spending time inspecting the machine to look for problems, they already know exactly what the problem is. They have been able to order the necessary parts and mobilize the necessary personnel ahead of time, rather than doing everything at overtime rates with expedited delivery charges.

#8 – It's the Process

While labor costs and repair parts represent non-trivial expenditures, the process itself is often where the real money is found. And this ties back to point #3. Instead of relying solely on financial justifications that help reduce maintenance costs, think about ways that condition monitoring reduces process interruptions and look for ways to monetize that. If necessary, position the condition monitoring software not as a maintenance tool, but as an operations tool, designed to protect the process. Leverage the fact that process conditions and machinery life are often inseparable. Indeed, one user has observed, "machines don't die, they're killed" referring to the ways that operating machinery in off-spec conditions (such as pumps unwittingly operating in cavitation or hydro units running in their rough load zone) can dramatically accelerate wear and shorten useful life. System 1 software can put these conditions in front of operators, allowing them to make decisions that balance the needs of the process with the needs of the mechanical assets.

#9 – Think Remote

The remote monitoring capabilities of online condition monitoring tools have come a long way in the last decade. While at one time it was simply impractical to think that machinery could be adequately monitored from arm's length using a phone line and a computer monitor, high-speed networks, the internet, video conferencing, and other technologies have truly made it possible to "move data, not people" without sacrificing the quality of machinery management. For users with multiple facilities, this can be especially important. Today, it is entirely practical to monitor a number of facilities from a single, centralized location. While the old model required a machinery expert to be physically present at each facility, we are seeing more and more users adopt an "Operations Center" approach where a centralized group of machinery experts is able to monitor a number of plants, often at ratios of 2:1 or better. For example, a user with 10 facilities would have at one time required at least 10 dedicated machinery engineers (one for each plant) to monitor the equipment. Today, those same users can do the same thing with five people or less by putting the experts in a single location and streaming the data to a centralized location where the experts reside. This model is also very important for machinery OEMs and service organizations that maintain a large number of long-term contractual service agreements and need to monitor this equipment remotely.

[Editor's Note: For an example of how one customer is using remote technology to continuously monitor 13 separate facilities with a team of just 6 people, see the Case History on page 24 of this issue.]

#10 – Tag Along

When a large project comes along, such as a process or machinery control system upgrade, the incremental costs to include condition monitoring software are often quite small in relation to the overall project cost. The economies of scale are better, too, as the electrical contractors to pull wires and install cabinets, the project management team, and the resources to generate drawings and other documentation will already be on-hand. Try to combine a project to install condition monitoring software with a larger project when possible. The costs will generally be lower and everyone will usually be more receptive because it is lest disruptive than a stand-alone project.

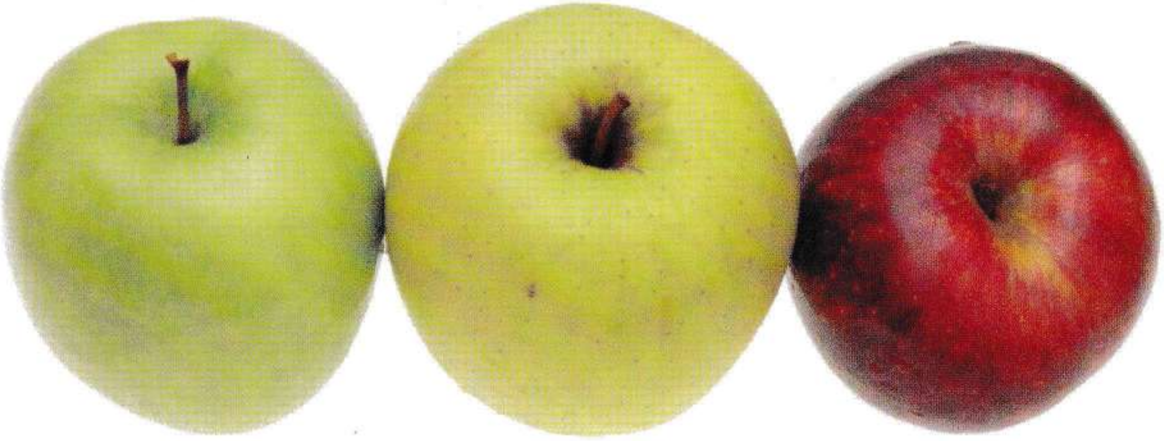
#11 – Make IT Your Friend

Users are finding it increasingly difficult to purchase special-purpose computer servers, software, and network infrastructure for things like control and monitoring applications. In fairness, Information Technology departments generally recognize the necessity of such systems, but they are trying to lessen the burden of having to maintain and support so many different applications. As such, there are often tremendous pressures in most companies to reduce the number of software packages and consolidate functions onto single servers and computing platforms when possible. Because System 1 software combines numerous applications that used to reside on independent computers and required separate software packages, it has a definite impact on lowering the cost of ownership, regardless of whether you face IT obstacles in your company. Examples include training (since training is only required for one product, not several) and the elimination of technical support agreements from multiple vendors for multiple products. Several of our users have employed these IT/maintenance considerations to help augment their financial justifications for purchasing System 1 software because it represents less hardware and software to support and maintain. Often, your IT department will already have financial data in-hand regarding the total life-cycle costs represented by each new computer, network cable, and software application. Use this data where possible to help augment your financial case for an integrated condition monitoring environment rather than numerous stand-alone applications.

"INSTEAD OF RELYING SOLELY ON ARGUMENTS THAT HELP REDUCE MAINTENANCE COSTS, THINK ABOUT WAYS THAT CONDITION MONITORING REDUCES PROCESS INTERRUPTIONS AND LOOK FOR WAYS TO MONETIZE THAT."

#12 – Make the Insurance Company Your Friend

Most plants carry industrial insurance to cover process interruptions. It is very, very common for these insurers to look at the installed instrumentation systems on machinery and adjust premiums accordingly. Plants with a high degree of machinery protection and monitoring sophistication obtain better premium rates than those that do not because machinery failures relate directly to process interruptions. While at one time, the insurance companies looked primarily at just the monitoring hardware, they are increasingly looking at the installed software systems as well because they recognize the proactive capabilities the software provides. If your insurance company provides more favorable premiums for those users with online software installed, obtain this data and use it as part of your financial justification.



#13 – Sell the System Internally as "Knowledge Retention"

Companies are coming to the realization that many of their most knowledgeable people are retiring, and with those retirements, valuable knowledge is being lost. One estimate is that as much as 50-60% turnover will occur in the next 10 years at many companies. While all of that turnover will not be due to retirement, a sizable amount will be. And, even if those vacancies are filled with experienced people, they often don't possess knowledge specific to your own processes and procedures. Systems that allow users to embed knowledge are consequently becoming more important; this should not be mistaken with sophisticated "expert systems" designed to automate machinery diagnostics. Instead, by embedding knowledge we mean systems that allow users to capture notes, correlations, and other information that typically only comes from years of hands-on experience dealing with the idiosyncrasies of a particular piece of equipment or process. While these systems aren't designed to replace people, they are designed to capture the knowledge of individuals so that it can be more easily retained and shared.

#14 – Sell the System as a Planning Tool

Closely tied into item #6 above is the concept of outage planning. It is easy to get caught in the trap of thinking about a condition monitoring system as only an "alarm" system that tells you when there is a mechanical or process problem. But consider the flip side of this: it also tells you when there isn't a problem. Users have repeatedly told us that their systems are providing value because they don't waste time working on things that don't require attention, such as replacing parts based on calendar intervals rather than actual useful-life-remaining. In some cases, this translates directly to extending the intervals between outages or eliminating a planned outage entirely. An excellent example of this is in the article "25 Years of Condition Monitoring Experience at E.ON. Benelux" which appeared in ORBIT Vol 26, No. 2, 2006. Even when an outage is planned, its duration can generally be made shorter and its costs reduced because time and money is not wasted inspecting or replacing items unless condition data warrants. So remember, your condition monitoring system can provide value not just in what it tells you, but in what it doesn't tell you.

#15 – Turn Negative Events Into Opportunities

Nobody wants to experience process interruptions, machinery failures, and mechanical catastrophes in order to create a compelling business case, but the truth is that following such events, people are more acutely aware of the costs and repercussions of failure. If a failure does occur in your plant, use it as a learning opportunity to quantify the implications of the failure and reinforce the business case for condition monitoring software. You may find the business climate distinctly receptive to investments in technology that can help prevent a reoccurrence.

#16 – Don't Put All Your Eggs in One Basket.

Sounds like conventional investment advice, doesn't it? As crass as it may sound, some items, such as term life insurance, are sold purely on fear. Equally crass, other items are sold purely on greed, such as high-return, short-term stock market investments. In reality, though, many industrial expenditures represent a complex mix of these two factors. When possible, provide multiple reasons, with both positive and negative reinforcement (i.e., "fear" and "greed") to help build your case.

Summary

Developing the justification for a needed expenditure is never a particularly enjoyable activity, but it is a reality of business. And because the language of business is inherently the language of finance, it is important to be able to recognize as many ways as possible in which condition monitoring software can contribute financially to a business. Here, I've offered 16 ways that users have built the business case for their purchase of System 1 software. Although many are common sense, I hope you have found it helpful to have them summarized in a single location. In closing, although the list is reasonably comprehensive, it is not exhaustive. If you have found additional ways to justify the purchase of condition monitoring software in your organization that would augment the points I have summarized here, I encourage you to contact me. I'd love to hear your story regarding not just how you developed your organization's business case, but also in how your software is delivering benefits now that it is installed.

Synopsis of Savings

System 1* Identifies Generator Field Problem, Keeps Unit Online Until Scheduled Outage

A large refinery has an onsite power generation facility consisting of five gas turbines and four steam turbine generators to provide steam and electricity for the rest of its operations. The machines are monitored with GE's Bently Nevada* 3500 series machinery protection systems and System 1 software. The System 1 software allowed the plant to identify a thermal sensitivity issue in one of the generators by correlating vibration levels with load and VAR (field current) changes. Without this data, the plant would have attempted to correct the problem by balancing the generator and would have missed the problems with the generator field. By understanding the nature of the problem, the plant was able to avert a major failure that would have occurred had the generator field shorted out during peak load. The plant estimates that it **saved an 8-week outage and nearly $1 million** by instead planning repairs for the upcoming scheduled outage and running the unit at reduced load until that time.

Remote MDS Assistance and System 1 Software Saves 1 Million Euros

A methanol plant in Europe was experiencing high vibration on one of its critical compressor trains. The units are monitored with GE's Bently Nevada machinery protection systems and System 1 software. Because the vibration rose to alert levels within one minute, these vibration changes never would have been spotted without a continuous monitoring system. Although the plant did not have personnel on staff able to examine the data from their System 1 software, they were able to enlist the assistance of their local GE office and the Bently Nevada machinery diagnostic services (BNMDS) engineers located there. Examination of the vibration and process data allowed the BNMDS engineers to conclude that a portion of the demister had entered the suction side of the compressor, but was not endangering the machine. The plant elected to keep the units running. Without this information, the plant would have had to stop to conduct a machinery inspection, causing at least **10 days of lost production and a loss approaching 1 million Euros.**

Cement Plant Saves Millions with System 1 Software

A large cement plant uses a combination of online and offline vibration monitoring hardware in conjunction with GE's System 1 software to provide an integrated environment for all equipment condition. The system was recently used to identify a problem on a gear mill reducer. The mill was changed out before it could progress to a catastrophic failure. Had the problem not been identified in time, the gear could have failed completely, reducing plant throughput, and forcing the plant to wait six months for a replacement unit. The cost to replace the gear unit in a planned fashion was $2.5 million. In contrast, the six-month wait for a new gear coupled with reduced plant output by the loss of one mill **could have totaled nearly $80 million.**

The plant used the system to identify another problem, this time on a dust collector fan. By identifying the problem early and conducting condition-based maintenance, they spent only $2,000 with minimal downtime in contrast with the **$135,000 that would have been spent** had the machine progressed to total failure and incurred **nearly 12 hours of downtime.**

System 1 Software Improves Availability of Coal Pulverizers, Averts Forced Outage

A coal-fired power plant in Asia uses GE's Bently Nevada Trendmaster* platform and System 1 software to monitor its coal pulverizers. The units historically suffered from low availability (below 90%). Within just a few months of system installation, availability increased by five percentage points to 93% and was steadily improving. The system also helped engineers quickly identify a

Taking Excellent Care of Our Customers

In February, I joined GE's Optimization and Control team as the global sales leader after more than nine years in various commercial leadership roles within GE. Optimization and Control is an exciting business. Why? Because it is growing on a global basis and is full of dynamic technology innovations. It is also growing the old-fashioned way: by listening to the needs of our customers and then delivering—consistently.

Although GE leaders have always been expected to maintain a strong external focus, there has never been a time within GE where this has been more important or emphasized more heavily. Our external focus is all about our customers. If you cannot walk in your customers' shoes, if you cannot demonstrate excellent listening skills, and if you cannot translate the needs of customers back into the organization to ensure that we are doing the right things to meet and exceed customer expectations, then—to be quite blunt—you have no business being in sales, and you certainly have no place on the optimization and control sales team.

I'm pleased to report that the culture within the optimization and control sales team has external focus deeply ingrained. The people that comprise our sales force have deep technical knowledge and application experience, and we work hard to maintain this expertise. Our salespeople are not generalists, expected to sell everything in the GE portfolio. Instead, we want them to have deep knowledge about the specific product lines for which they are responsible, whether thermodynamic performance software, reliability services, machinery controls, oil and gas downhole exploration technologies, plant optimization software, or Bently Nevada* condition monitoring systems.

But in addition to domain knowledge, I have also found a team of people that knows how to take excellent care of you—our customers. Our sales professionals know how to listen, and it is very important to me that we not only maintain this ability, but also improve it. As such, one of the things I'll be emphasizing as we move forward is the ongoing importance of what we call "Voice of the Customer" at GE. It's exactly what it sounds like—the importance of hearing your voice regarding what we do and how we do it, and ensuring that you always have direct and timely access to us.

In the past several years, we've done several things to enhance this, and we will continue to do more. For example, we have launched a series of global user's conferences, ensuring that you have a forum not only to learn what's new from us, but we have a forum to hear from you. I'm also emphasizing with our teams the importance of single-company sessions where we devote time solely to your business, understanding the unique challenges you face in the marketplace—

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challenges that may or may not be common to other companies, and ensuring that we are doing everything possible to assist you. We have also recently opened a network of seven global Customer Application Centers where hands-on access to our technology through demonstrations, training, and seminars is offered. Every one of these has been launched with a specific goal in mind: making ourselves more accessible to hearing the voice of our customers.

I'm privileged to be leading such a great team of sales professionals, and my role is largely one of improving the things we are already doing well. But although I trust we are meeting the majority of your needs today, I realize we can always do better. I invite you to contact me personally at any time to let me know how we are doing, and to suggest ways that we can raise the standards whether through something as high-tech as a new sensing product, or something as low-tech as having the right resources in the right places.

It's great to be part of this business. We've got great products, great services, and great people that combine domain knowledge with strong customer-centric behavior. I am absolutely committed to maintaining and enhancing this strong external focus. It's a focus that has always been a part of our culture, but can never be emphasized too much: *taking excellent care of our customers.* ◼

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An All-New Version of the ProxPac* Probe Housing Assembly

Now with 3300 XL technology

A conventional proximity transducer system installation consists of the probe, its extension cable, and a Proximitor* signal conditioning module. While the probe must obviously be mounted at the measurement location (i.e., on the machinery), the Proximitor signal conditioning modules for several probes are typically grouped together in a common junction box, located off the machine where they are easily accessible. From the junction box, the Proximitor modules are connected by field wiring to their associated monitoring system (such as 3300 or 3500). This arrangement is shown in Figure 1.

While many users find it convenient to group the Proximitor modules into junction boxes in this manner, and while this method is specified for those installations that must strictly conform to API 670 requirements[1], other customers prefer our ProxPac solution, which reduces installation costs. The ProxPac design was first introduced in 1995 and is essentially a standard proximity probe housing assembly with the Proximitor module mounted inside. This innovative design eliminates the need for an extension cable and allows the field wiring from the monitor to be run all the way to the probe housing, rather than via an intermediate junction box (Figure 2).

The original ProxPac design was based on 3300 proximity transducer technology, which—while very good—cannot deliver the enhanced electrical performance and mechanical improvements of the backward-compatible 3300 XL system. Today, we're pleased to announce that ProxPac assemblies are available with 3300 XL technology. Customers that choose an installation using the ProxPac approach can now benefit from both ease-of-installation and our most advanced transducer technology in a single package. A slightly larger housing cover has been designed that accommodates a standard[2] 3300 XL Proximitor module, allowing customers the benefit of not just improved electrical performance, but a more rugged design that is easier to connect to field wiring using innovative SpringLoc* wiring terminals. This design keeps the mechanical footprint nearly the same, meaning the new ProxPac will work wherever the previous ProxPac design would work[3].

To learn more, talk to your nearest GE Energy sales professional specializing in Bently Nevada* Asset Condition Monitoring products. You can also request a copy of the ProxPac datasheet by using the Reader Service Card inserted in this issue of ORBIT, or by accessing the online version of the Reader Service Card at www.orbit-magazine.com.

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[1] API 670 requires that oscillator/demodulator (i.e., Proximitor) modules be mounted in junction boxes off the machine, and that all junction boxes be mounted on the same side of the machine for ease of access. The purpose of this requirement is to ensure that oscillator/demodulator modules are not subject to mechanical vibration that could fatigue connections inside and outside the device. Our ProxPac assemblies, however, are specifically designed to operate reliably in such environments without concern that internal or external connections will vibrate loose.

The new 3300 XL ProxPac assembly combines ease-of-installation and lower installation costs with our most advanced transducer technology.

Figure 1 – A conventional proximity transducer system installation using a junction box to house the Proximitor modules.

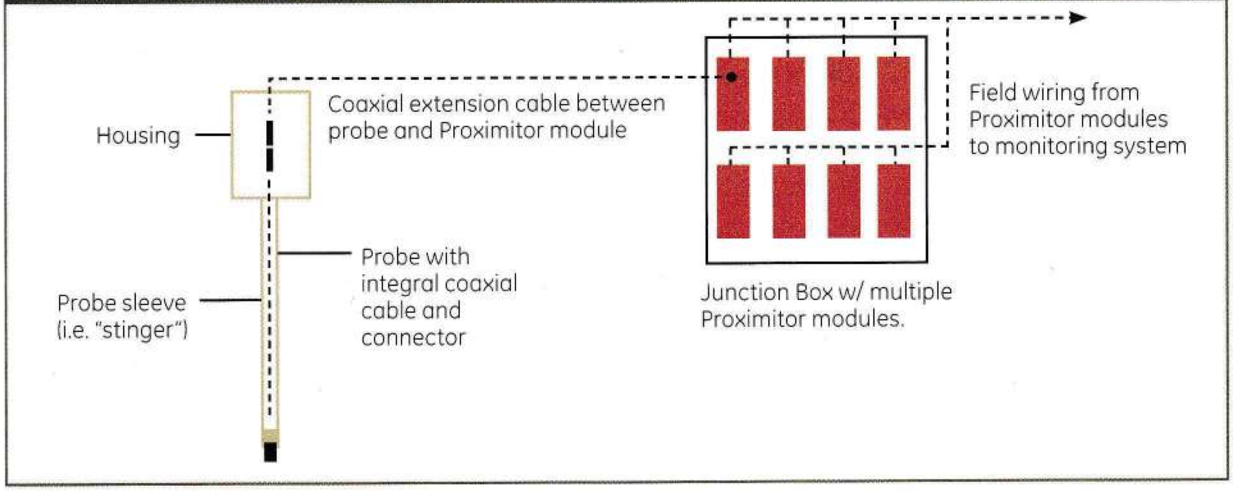
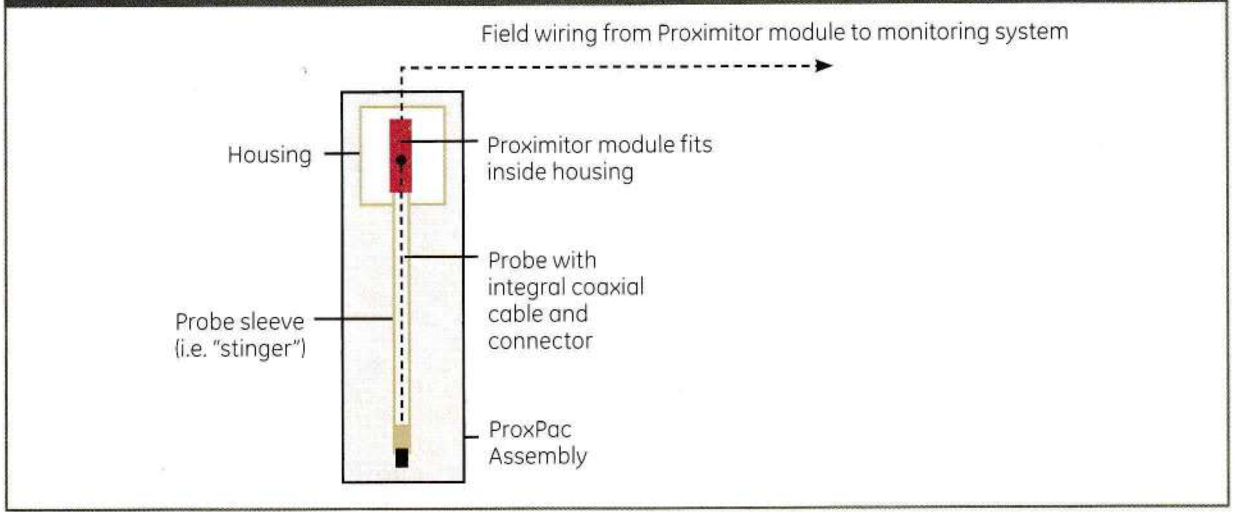

Housing
Coaxial extension cable between probe and Proximitor module
Field wiring from Proximitor modules to monitoring system
Probe sleeve (i.e. "stinger")
Probe with integral coaxial cable and connector
Junction Box w/ multiple Proximitor modules.

Figure 2 – A proximity probe installation using the ProxPac assembly. This design eliminates the need for an extension cable and an intermediate junction box, lowering installation costs.


Field wiring from Proximitor module to monitoring system
Housing
Proximitor module fits inside housing
Probe with integral coaxial cable and connector
Probe sleeve (i.e. "stinger")
ProxPac Assembly

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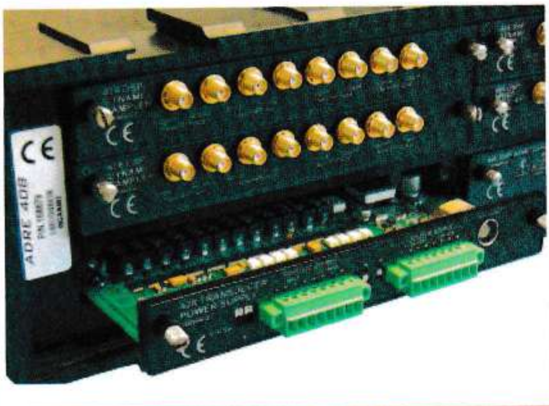
[2] The Proximitor module used in the 3300 XL ProxPac assembly is identical in construction and appearance to our standard 3300 XL 8mm version. It has been tuned, however, to accept a 1 meter cable length,

[3] The dimensions of the new ProxPac assembly are identical to the previous version and to our standard 31000 proximity probe housing with exception of the depth which has increased by 17.8 mm (0.7 inches). Conduit connection locations remain identical as well, and can be made at the top, left, or right side side of the housing.

ADRE* Transducer Power Supply Module

Integrated power supply provides power for accelerometers, proximity probes, velocity transducers, and more

The new transducer power supply module occupies a single slot in the ADRE DSPi 408 chassis and provides power for a wide range of transducers.



A new module for the ADRE portable data acquisition and analysis system is now available, providing power for a wide variety of displacement, velocity, acceleration, and other transducer types used in field and test stand applications.

A primary design objective of the new ADRE system was to eliminate the need for carrying extra devices such as oscilloscopes, spectrum analyzers, tape recorders—and power supplies. As anyone who has worked in the field understands, simply mounting temporary, supplemental transducers is only half the battle; they must then be powered. In the past, this meant lugging one or more power supplies to accommodate the various power requirements of proximity probes, constant-current (i.e., ICP) accelerometers, non-ICP accelerometers, and other transducers, such as those running on +24 vdc.

The new module can simultaneously power up to 32 transducers in various combinations. It provides direct physical connections for 16 transducers (eight +/–24 vdc transducer systems and eight accelerometer/velocity transducer systems). Additional transducer connections can be accommodated using accessory connection adapters and an external breakout panel[1]. In addition to +/- 24 vdc selections, +/- bias selections are available for constant current applications, all of which can be used simultaneously providing a highly flexible power source for most any need. Transducer power is user-configurable in blocks of four directly from the card without the need for special tools, jumpers, or software.

The module's design provides each output with individual short-circuit protection and indicators for power status and voltage/current selection (complete card status is provided within ADRE Sxp client software). Also, users do not need to sacrifice channel capacity when using the new power supply module because it occupies a dedicated option slot on the back of the ADRE DSPi 408 chassis, leaving all transducer input slots available.

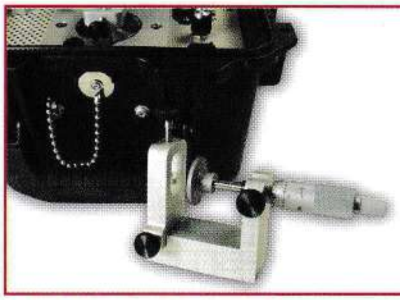
Capabilities for future functionality have been incorporated that will allow users to configure outputs for custom voltage supply requirements via the external breakout panel[1]. This will allow powering older proximity systems that run on –18 vdc or +15 vdc, or industrial sensors that use non-standard supply voltages such as 6.5 vdc, making the ADRE system compatible with and capable of powering virtually any transducer type.

To learn more, contact your nearest GE Energy sales professional specializing in the Bently Nevada product line. You can also request a copy of the ADRE datasheet by using the Reader Service Card in this issue of ORBIT, or by accessing the online version of the Reader Service Card at www.orbit-magazine.com.

[1] The external breakout panel will not available at initial release, but is a planned future enhancement.

TK-3 Proximity System Test Kit

Completely updated calibration instrument features improved portability, ruggedness, and flexibility



The TK-3's new detachable spindle micrometer provides added flexibility.

The specialized nature of proximity probe measurements requires a specialized calibration instrument, capable of introducing fixed gap (i.e., position), changing gap (i.e., vibration), and rotative speed signals into the transducer for verification and testing purposes. Fixed gap is provided by clamping the probe into a stationery position while a movable target on a spindle micrometer is adjusted. Simulated vibration is provided by clamping the probe into a movable swing arm, observing a precision-machined wobble plate that rotates, introducing a known amount of changing gap with each rotation. Finally, shaft rotative speed is simulated by observing a Keyphasor* notch on the side of the rotating wobble plate.

The TK-3 Wobulator* provides all of these functions in a portable kit, designed specifically to endure the rigors of field use. It allows users to test and verify the entire measurement path, from the tip of the probe all the way through to the monitor's visual indicators, relay contacts, and digital/analog interfaces.

Today, we're pleased to announce an all-new TK-3. Our engineers consulted extensively with customers and our own field service personnel to ensure that this new test kit retained the simplicity and functionality of its predecessors, while providing enhanced durability, reliability, and usability.

Our popular TK-3 Proximity System Test Kit has been completely redesigned and is available in both air-powered (left) and electric-powered (right) versions.

- The weight has been reduced by 20% for easier carrying from shop to jobsite.
- Available in both air-powered[1] (TK-3g) and 110/220 Vac electric-powered (TK-3e) versions.
- An all-new industrial-strength case dramatically improves durability, able to withstand the rigors of field use while better protecting the precision devices inside.
- The drive motors of both versions are completely maintenance-free and the air-powered version now incorporates a filter that helps to further prolong the life of the motor.
- A detachable spindle micrometer with magnetic base allows users to carry only the micrometer to the probe location rather than toting the entire test kit. For example, one person can be generating probe curves while another is simulating vibration to perform loop checks and verify monitoring system displays.
- A universal probe mount accomodates probe diameters from 5 to 19mm, eliminating the need for multiple adapter collars when clamping probes into the micrometer or wobble plate—fewer parts to fumble with in the field, fewer parts to misplace.

Additional information is available in the TK-3's datasheet. Request a copy from your nearest GE Energy sales professional specializing in Bently Nevada* Asset Condition Monitoring products, or by using the Reader Service Card in this issue of ORBIT. You can also instantly access a copy by using the online version of our Reader Service Card at www.orbit-magazine.com.

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[1] The TK-3g is powered with compressed air (up to 100 psi) and is intended for use when electric power is not readily accessible or when the kit will be used in a hazardous (flammable) atmosphere. Hazardous area approvals for the TK-3g are currently pending and are expected by late 2007.

New Stand-Alone Tach100 Tachometer Now Available

Compact, panel-mount tachometer is ideal for local or remote speed indication

Highly accurate indication of rotational speed is a fundamental instrumentation requirement for many machines. Tachomters using a 4-20mA input signal are rarely capable of providing the necessary accuracy or resolution; instead, tachometers accepting a pulse-train signal from a once-per-turn or multiple-event-per-turn transducer are preferred due to the superior resolution and accuracy this type of input signal can provide.

For more than 35 years, the Bently Nevada* product line has featured a variety of stand-alone tachometers as well as tachometer modules used in our rack-based machinery monitoring systems. For the reason noted above, these tachometers are designed to work with a proximity probe input from a once-per-turn shaft discontinuity, such as a key or keyway, or a multi-event-per-turn precision toothed wheel.

One of our most popular tachometer styles over the years has been the 37506A, a small panel-mount indicator with a large, easy-to-read display. Customers continue to find many applications for the 37506A, but it is becoming increasingly difficult to support due to the diminishing availability of certain parts. Our goal was to provide an updated tachometer that retained the same physical dimensions and functionality as the 37506A, but with updated electronics. The new Tach100 is the result.

The Tach100 is designed to support the same applications as the 37506A, such as stand-alone scenario when speed indication is required locally at the machine, or at a remote location such as a control room. Another very common application of the tachometer is when speed indication is required in two separate locations simultaneously. Often, a monitoring rack with an installed tachometer will already be available in one location, such as a control room or instrument shelter. The Tach100 can be installed in parallel with the monitoring system, sharing the same transducer input signal, but providing speed indication in a secondary location, such as the machine's control panel.

Additional information and diagrams showing typical installation scenarios are available in the Tach100's datasheet. You can obtain a copy by contacting your nearest GE Energy sales professional specializing in Bently Nevada Asset Condition Monitoring products, by using the Reader Service Card in this issue of ORBIT, or by accessing the online version of the Reader Service Card at www.orbit-magazine.com.

Key Features

- Compatible with newer –24Vdc proximity transducers [1,2]
- 1 rpm resolution with improved accuracy (+/- 0.15% of true RPM)
- Front-panel adjustement of trigger levels and event-per-turn settings
- Same physical dimensions as 37506A, making retrofits simple
- Compatible with 37506A accessories, such as hood to block direct sunlight and weatherproof housings for outdoor installations

Sharing the same physical dimensions and features, the new Tach100 (left) is a comprehensive update to our popular 37506A panel-mount tachometer (right).

---

[1] When retrofitting systems using older +15Vdc tach drivers, contact your local sales professional for assistance. These applications require upgrading the transducer system to newer –24Vdc technology.

[2] When retrofitting systems using older –18Vdc proximity probe technology, a voltage adapter is available that converts –24Vdc transducer power to –18Vdc.

Mechanical Protection for Cylinder Pressure Transducers

Cylinder pressure measurements provide critical information about the condition of reciprocating compressors. Such transducers provide the all-important pressure-volume (PV) measurements needed to assess mechanical and thermodynamic performance of the cylinder and other parts of the machine. For reciprocating compressors, the internal cylinder gas pressure generates forces on the piston rod and these forces are typically larger than combined effects from inertia loads, rotating imbalance, etc. Accurate information about the cylinder gas compression cycle provides critical insight into the machine's running condition and the operating stresses experienced by the various compressor components.

Although data provided by these transducers can be used to greatly improve machine safety and reliability, it is imperative that the installation provides adequate structural bracing of the transducers and associated isolation valves. Failure to install such bracing introduces a very serious safety hazard because if a transducer or valve were to break due to improper installation or physical abuse (see Figure 1), gas would be vented directly to the atmosphere. Indeed, the suction valves in the cylinder will allow all available gas in the bottles, coolers, and piping to vent to the atmosphere even if Operations were to immediately isolate the compression system at the instant the breakage occurs. When hazardous or flammable gases are used, as is often the case with reciprocating compressors, the consequences are even more serious.

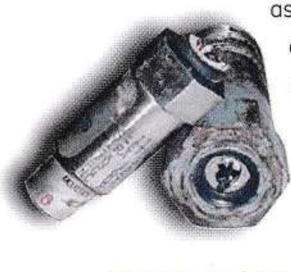


Figure 1 – Broken cylinder pressure transducer due to Inadvertent contact with an overhead crane hook.

Brian Howard, P.E.
Field Applications Engineer,
Reciprocating Compressor Condition Monitoring
GE Energy
brian.howard@ge.com

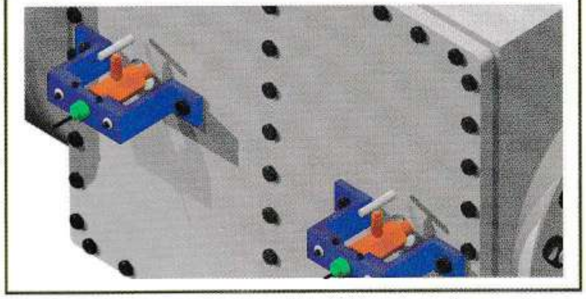
Adequate structural bracing safeguards against this in two ways:

1. It provides additional stiffness that helps reduce effects of vibratory resonance and the potential for fatigue-induced failures.
2. It provides an additional layer of mechanical protection, guarding the pressure transducer and isolation valve from the accidental impact of an overhead crane hook, dropped tools/parts, a worker's boot stepping in the wrong place, or similar scenarios.

Figure 1 shows the damage that resulted from an overhead crane hook contacting a cylinder pressure transducer. Fortunately, the primary diaphragm remained in the valve so no release of gas occurred. Further, the bracing extended to the isolation valve so it remained in place and allowed plant personnel to immediately isolate the damaged diaphragm from the internal cylinder pressure.

Figure 2 shows a design for an adequately braced cylinder pressure transducer. At a minimum, the bracket should be designed to have a first mode resonance above 100X running speed. This usually requires the plate be 0.50" [12mm] thickness or greater. Substantial bolts (½" nominal size or larger) should be used to secure the bracket to the cylinder body. For a detailed design specific to your application, contact your local GE sales professional specializing in Bently Nevada* asset condition monitoring products and services.

Figure 2 – CAD rendering showing design for an adequately braced cylinder pressure transducer
(bracing in blue, isolation valves in orange, tranducers in green).



2007 Users Conferences

Unlock even more value from our control, condition monitoring, and reliability products and services by exchanging best practices with your peers.

GE Energy's optimization and control team is pleased to host customer user conferences in five key locations across the globe in 2007. These conferences bring together users of GE's System 1 and related monitoring and diagnostic software, Bently Nevada Asset Condition Monitoring products, and plant-wide and rotating machinery controls. The events draw users from all levels of experience and a wide variety of industries with agendas that include user presentations, new product introductions, breakout training sessions, user networking, and more.

While some of these events have already occurred, we're including them here for reference—you can anticipate similar conferences and venues for 2008 and beyond.

To learn more, visit www.ge-energy.com/unlock or contact your nearest GE Energy sales professional.

Amsterdam, The Netherlands
13-15 March 2007

Dubai, UAE
14-16 May 2007

Houston, Texas USA
17-19 July 2007

Singapore
1-3 August 2007

Hangzhou, China
16-19 October 2007

Hydro Oil & Energy's New North Sea Operations Center Cuts Production Losses

Land-based monitoring and control center for offshore oil fields has already saved millions

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The Troll C platform, one of 13 offshore facilities monitored by System 1* software in Hydro Oil & Energy's new land-based operations center in Sandsli, Norway.

With a fleet of 35 gas turbines, 30 compressor trains, and 220 production-critical pumps operating across offshore facilities in the rough waters of the North Sea, Norway's Hydro Oil & Energy had a goal: to be able to monitor and control the mission-critical rotating machinery at every one its 13 oil fields on the Norwegian Continental Shelf from a central operations center.

This article chronicles the evolution of the operations center, highlights the role GE Energy's products and services have played in its success, and provides several case histories illustrating the types of machinery problems that are being solved and the economic benefits realized by the ability to remotely monitor and diagnose problems.

Integrated Operations

In development since 2003, the new land-based Operations Center in Sandsli, Norway, connects subsea installations at Vale, Tune, and Fram with offshore platforms at Oseberg, Brage, Njord, Troll, Heimdal, and Grane under a single roof for monitoring mechanical and thermodynamic condition. Throughout this time, Hydro Oil & Energy has worked closely with GE Energy to replace their old condition monitoring systems with upgraded technology that allows them to control all of their critical rotating machinery at a level of precision previously considered impossible. The Operations Center builds upon Hydro's extensive experience in monitoring critical offshore machinery and is permanently staffed by six specialists who work around the clock in two-person shifts. These specialists can now work in concert with their offshore counterparts, helping to prevent potentially catastrophic equipment failures that can cause millions of dollars in lost production. GE's System 1* Online Condition software and underlying Bently Nevada* vibration monitoring hardware comprise a critical part of the instrumentation systems in the new Center.

Officially opened on February 7, 2007, the dedication of the Sandsli Operations Center was attended by dignitaries such as Gunnar Berge, Director General of the Norwegian Petroleum Directorate. Rolf I. Jacobsen, Hydro Oil & Energy's director of Business Control and Improvements, was also on-hand for the ceremony and succinctly summarized the company's expectations:

"Use of new technology and work processes will help us keep equipment running constantly. This will contribute to considerable reductions in lost oil and gas production."

Clearly, GE Energy's technology was expected to deliver results.

Proving Its Value

Operating in some of the harshest weather conditions in the world, North Sea oil platforms incorporate an array of critical machinery trains that are essential to production. Failures of this machinery mean not only expensive repairs in inhospitable locations, but also potential production losses that can be enormous. To help prevent such catastrophic failures from occurring, Hydro's operations support team relies heavily upon GE's System 1 software to maintain a vigilant watch for

Figure 2 – Specialists inside Hydro Oil & Energy's Operations Center viewing equipment conditions and status via a variety of System 1 software screens.

signs of potential equipment failure. The advanced early warning capabilities of this software enhance the ability of the operations room specialists to respond quickly and avert costly breakdowns before they can interrupt production.

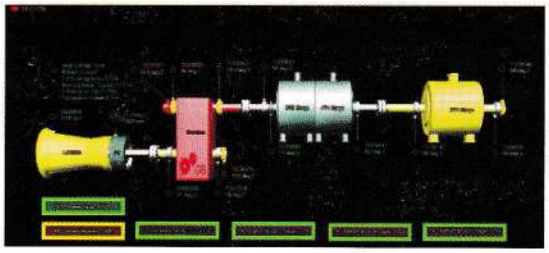
The system has already proven itself in a number of instances over the last several years—enabling the expert team in the operations center to provide rapid responses and efficient solutions. As explained by Geir Nodeland, the process owner for critical rotating equipment, "If we can discover something, we can warn the field units and together implement initiatives to keep the matter from developing into a larger problem." The following case histories are two examples of how the system is helping Hydro meet their objectives.

Case History #1: Lube Oil Supply Restriction

October 25, 2005

Hydro Oil & Energy's operation support team detects an alarm on a critical compressor train on the Troll B platform where the axial bearing temperature had increased to 103°C. The team closely monitors the bearing for any further changes in condition.

Figure 3 – Machine train diagram from System 1 software showing status conditions and readings. The red shading on the gearbox and it associated measurement point indicates an alarm status condition on the gear's axial (thrust) bearing. The elevated bearing temperature had reached 103°C.



November 2, 2005

The bearing's temperature increases to 108°C. The operation support team reports this to the offshore process operator and continues to monitor the problem remotely from the operation room.

November 8, 2005

The team concludes that with no other problems than high axial bearing temperature, the possible cause is a restriction in oil supply to the bearing. The compressor is deemed able to continue to run until the 120°C Trip Level for high bearing temperature is reached (the control system alarm is set at 110°C; bearing metal will start melting at approximately 140°C). Plans are made to replace the lube oil cooler to see if it can have any effect on lowering the temperature.

November 9, 2005

The lube oil cooler is replaced with no positive result. System 1 software shows that temperature has continued to increase and is now at 113°C. The operation support team concludes that the temperature will continue to increase and that oil supply restriction is the most likely cause. Hydro Oil & Energy decides to stop the compressor train for repair. The company shifts their planned outage in January up to November and begins mobilizing parts and personnel.

November 10-12, 2005

The compressor train is inspected, repaired, and quickly returned to service. As expected, the cause of the increased bearing temperature is confirmed as a restricted oil supply. Root cause is found to be contamination in the supply nozzle.

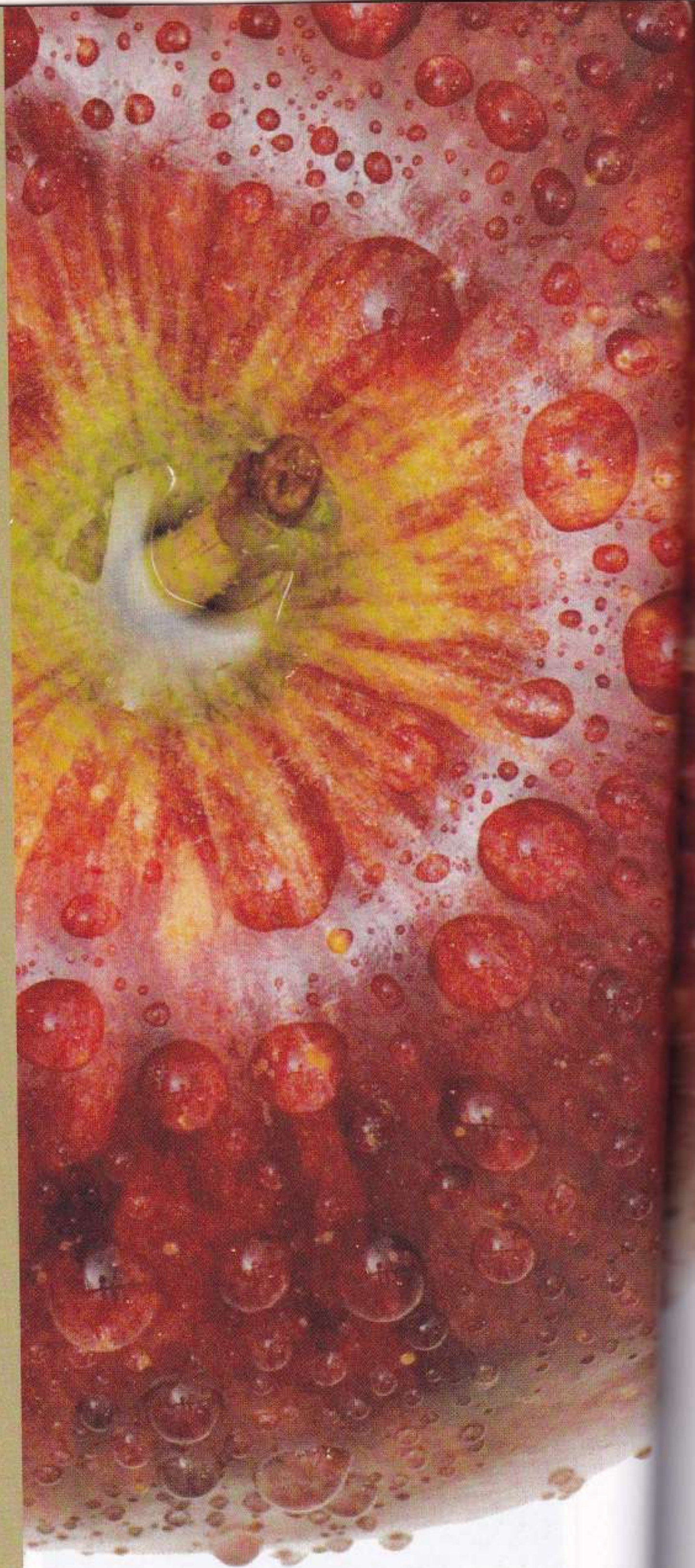
Business Impact

Through the use of System 1 software and the underlying Bently Nevada machinery protection systems, Hydro Oil & Energy was able to make an informed decision that the machine would fail catastrophically if allowed to run until a planned outage two months away. The outage was rescheduled, catastrophic failure was averted, and an estimated minimum of two extra days of downtime was saved. With production of 40,000 barrels per day and November 2005 oil prices at $65 per barrel, Hydro Oil & Energy saved an estimated 5.2MM USD.

Evolving Technology to Improve Offshore Operations

Since the beginning of Norway's petroleum industry in the 1970s, Hydro Oil & Energy has been involved in offshore operations and today it is the second largest operator on the Norwegian continental shelf. With decades of experience and a commitment to continually develop new technology to improve oil recovery rates, the company now operates Norway's most productive oil field—Troll Oil—despite the once-prevailing belief that its oil was unrecoverable. It was at this site that Hydro Oil & Energy installed the world's first subsea wellstream separation unit, which dramatically reduces the amount of water discharge, while increasing the amount of recovered oil. The company has also pioneered advanced horizontal drilling techniques and drilling multilateral wells to recover thin layers of oil from mature fields

Hydro Oil & Energy's Troll Pilot seabed separation system increases the production capacity of mature oil fields, while reducing the amount of water used in the process.



Case History #2: Performance Degradation Triggers a Water Wash

Early Sept 2004

Hydro Oil & Energy replaces inlet filters for the LM2500 gas turbines at Troll B. Although the new filters are designed for higher quality and better performance, shortly after their installation the thermodynamic performance module of System 1 detects a deviation in expected vs. actual isentropic efficiency (Figure 5).

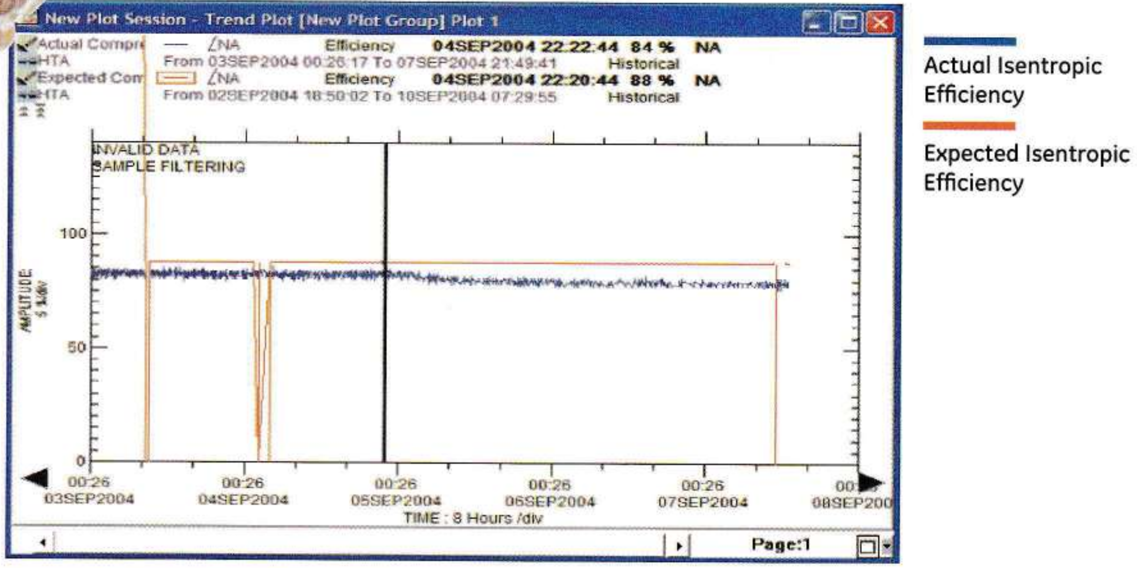
Sept 5, 2004

The isentropic efficiency drops to unacceptable levels, prompting the team to schedule a compressor wash of the affected turbine in an attempt to recover efficiency.

Sept 14, 2004

The compressor wash is completed, returning the unit to isentropic efficiency of 84–85% and closer to expected values (Figure 6).

Figure 5 – Performance trend showing actual versus expected isentropic efficiency of gas turbine following installation of new inlet filters.



New Plot Session - Trend Plot [New Plot Group] Plot 1

```
Actual Compr   —    ∠NA   Efficiency   04SEP2004 22:22:44  84 %   NA
HTA            From 03SEP2004 00:26:17 To 07SEP2004 21:49:41   Historical
Expected Com        ∠NA   Efficiency   04SEP2004 22:20:44  88 %   NA
HTA            From 02SEP2004 18:50:02 To 10SEP2004 07:29:55   Historical
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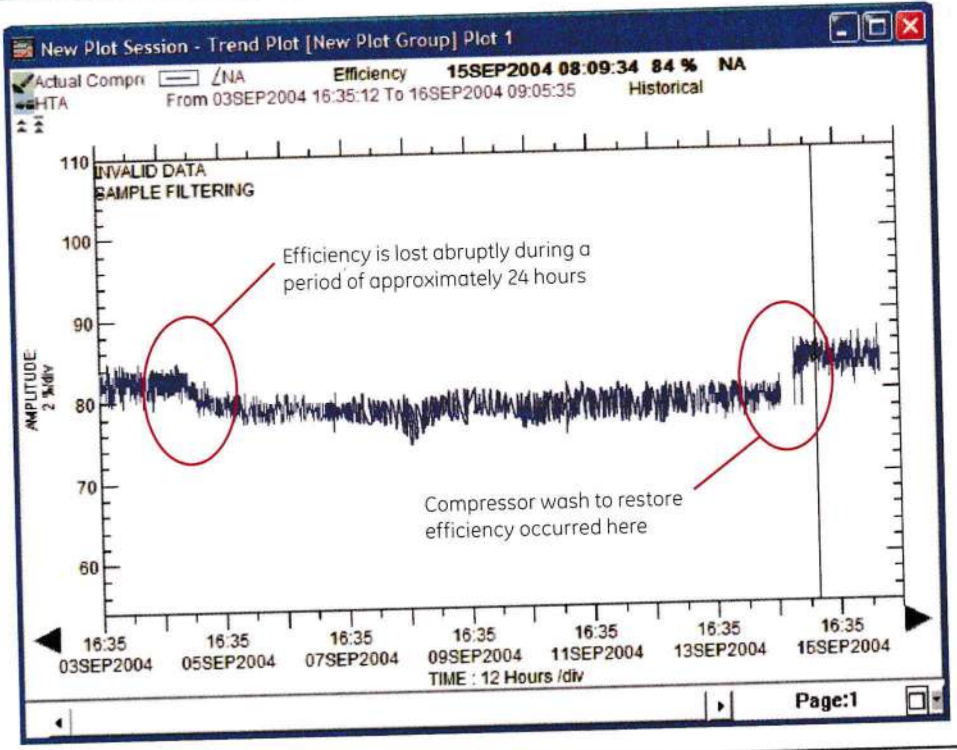
Figure 6 – Performance trend showing effect of water wash on 14 Sept 2004 to restore isentropic efficiency of gas turbine.



Efficiency is lost abruptly during a period of approximately 24 hours

Compressor wash to restore efficiency occurred here

Finding Root Cause

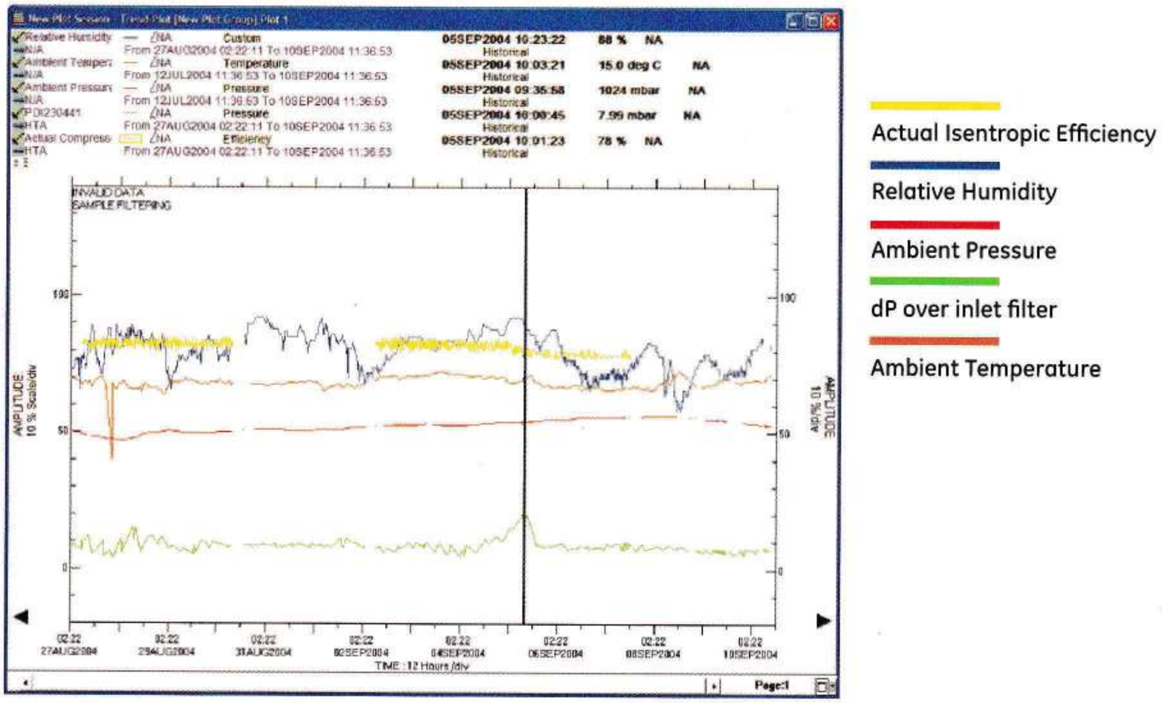
A drop in isentropic efficiency below 78% can make it harder to recover performance. As such, Hydro used this incident to begin a practice of setting software alarms at 80%, allowing adequate lead-time for planning a compressor wash. However, an important question still remained: why did performance deteriorate so quickly? Without the answer to this question, the team would become efficient in scheduling compressor washes, but could do little to extend the intervals between washes.

Normally, performance degradation occurs gradually over a period of months as build-up slowly accumulates in the compressor section of the gas turbine from particulates in the intake air. However, as can be seen by examining Figure 6, the drop in performance from approximately 84% to below 80% occurred during a 24-hour period between September 4 and 5, 2004. This abrupt change suggested a very different mechanism was at work, and to isolate the cause, the team began to examine additional data.

Using System 1 software's multi-variable trend plot capabilities (Figure 7), Hydro was able to examine numerous process and performance parameters simultaneously, looking for correlations and establishing cause/effect patterns. The following observations were made based on analysis of the data in Figure 7:

- Just prior to the drop in efficiency (marked by the black cursor position in Figure 7), the relative humidity had been increasing significantly for the previous 72 hours. During this time, there had also been small increases in ambient temperature and ambient (atmospheric) pressure.
- Differential Pressure (dP) across the inlet filter had risen significantly in the 24 hours prior to the efficiency drop

Figure 7 – Multi-variable trend plot with data that helped identify root cause as water retention/shedding in inlet filter.



```
New Plot Session - Trend Plot [New Plot Group] Plot 1
Relative Humidity  —  ∠NA   Custom        05SEP2004 10:23:22   88 %   NA
N/A   From 27AUG2004 02:22:11 To 10SEP2004 11:36:53   Historical
Ambient Temper:    —  ∠NA   Temperature   05SEP2004 10:03:21   15.0 deg C   NA
N/A   From 12JUL2004 11:36:53 To 10SEP2004 11:36:53   Historical
Ambient Pressure   —  ∠NA   Pressure      05SEP2004 09:35:58   1024 mbar   NA
N/A   From 12JUL2004 11:36:53 To 10SEP2004 11:36:53   Historical
PDI230441          —  ∠NA   Pressure      05SEP2004 10:00:45   7.99 mbar   NA
HTA   From 27AUG2004 02:22:11 To 10SEP2004 11:36:53   Historical
Actual Compress       ∠NA   Efficiency    05SEP2004 10:01:23   78 %   NA
HTA   From 27AUG2004 02:22:11 To 10SEP2004 11:36:53   Historical
```

- At approximately 10AM on September 5th, relative humidity, dP, and isentropic efficiency began simultaneously falling.

Based on these data and correlations, Hydro began to suspect that the new inlet filters were the most likely cause of the sudden performance degradation and postulated the following:

- As humidity rises, water content in the filter increases, resulting in "clogging" of the filter through accumulated water
- As humidity falls, this excess water in the filter is shed rather abruptly directly into the compressor section, along with water-borne particulates and contamination.
- The concentrated contamination quickly fouls the compressor section, resulting in reduced isentropic efficiency.

As a result of this analysis, the team worked with the manufacturer to again install filters with different specifications. While these improved the situation, under certain atmospheric conditions (heavy fog), the problems with water retention and shedding were still occurring. However, they were less frequent and Hydro was better able to anticipate them. Based on data they have collected and experience they have had with various filter designs over the past several years, further modifications to the filters and plenums are scheduled to occur in 2007. Hydro believes these changes will more fully rectify the problems.

Additionally, the team now alarms on elevated differential pressure (dP) across the inlet filter as well as when isentropic efficiency drops below 80%, providing another indicator for planning water washes on the unit.

Business Impact

Loss of efficiency in a gas turbine results in greater fuel consumption to maintain the same output power as well as increased emissions of CO_2 and NO_x. While the natural gas fuel on Hydro's platforms is "free" (natural gas is a by-product of the oil production process), free fuel is the exception in the vast majority of situations and direct fuel costs will normally be a significant factor in the financial justification for online monitoring. However, even with "free" fuel, there is still another type of fuel-related cost to Hydro: that of emissions taxes. CO_2 tax rates are currently based on fuel consumption and amount to approximately 2.6MM USD per year for each gas turbine. By reducing fuel consumption, Hydro is able to reduce these taxes.

NO_x taxes have recently been imposed as well. Operators have the choice of a flat-fee tax (approximately 1MM USD per year for each gas turbine), or a rate based on actual measured NO_x emissions. Most operators prefer actual NO_x measurements, as it allows them to reduce their taxes when they emit less, but it requires the installation of a Predictive Emissions Monitoring System (PEMS). Hydro will be switching to the PEMS-based method of taxation next year.

Thus, efficiency will have a direct influence on their CO_2 and NO_x taxes and even modest improvements in efficiency of a few percent translate to a reduction in emissions taxes of several hundred thousand dollars per year for each gas turbine. When this is applied across their fleet of 35 gas turbines, the financial impact multiplies to millions of dollars.

Summary

As shown in the successful resolutions to these two incidents, the enhanced condition monitoring capabilities of System 1 software provides the Operations Center with the ability to detect and monitor problems before they reach a critical stage, and to identify root cause so that problems do not reoccur. The advanced networking and communications capabilities of the system have allowed Hydro to implement a highly successful remote monitoring model for their 13 offshore facilities in the North Sea. Now, when problems occur, personnel in the Operations Center can contact operators at the offshore facilities using video conferencing and implement corrective actions in minimal time. This innovative model utilizing a centralized team of experts is proving itself to be more efficient than placing individual expertise at each site, allowing a team of six people to continually monitor 13 facilities, something that would have been impossible before implementation of the Operations Center.

As Geir Nodeland, process owner for heavy rotating equipment sums up: "This has been an extensive, exciting, and challenging project for both Hydro Oil & Energy and GE Energy. We now have an excellent tool, and we will continue to actively work together with GE to improve that tool in the years ahead." ◘

Minden Facility Achieves VPP Recertification

Exceptional emphasis on workplace safety and health results in highest level of certification

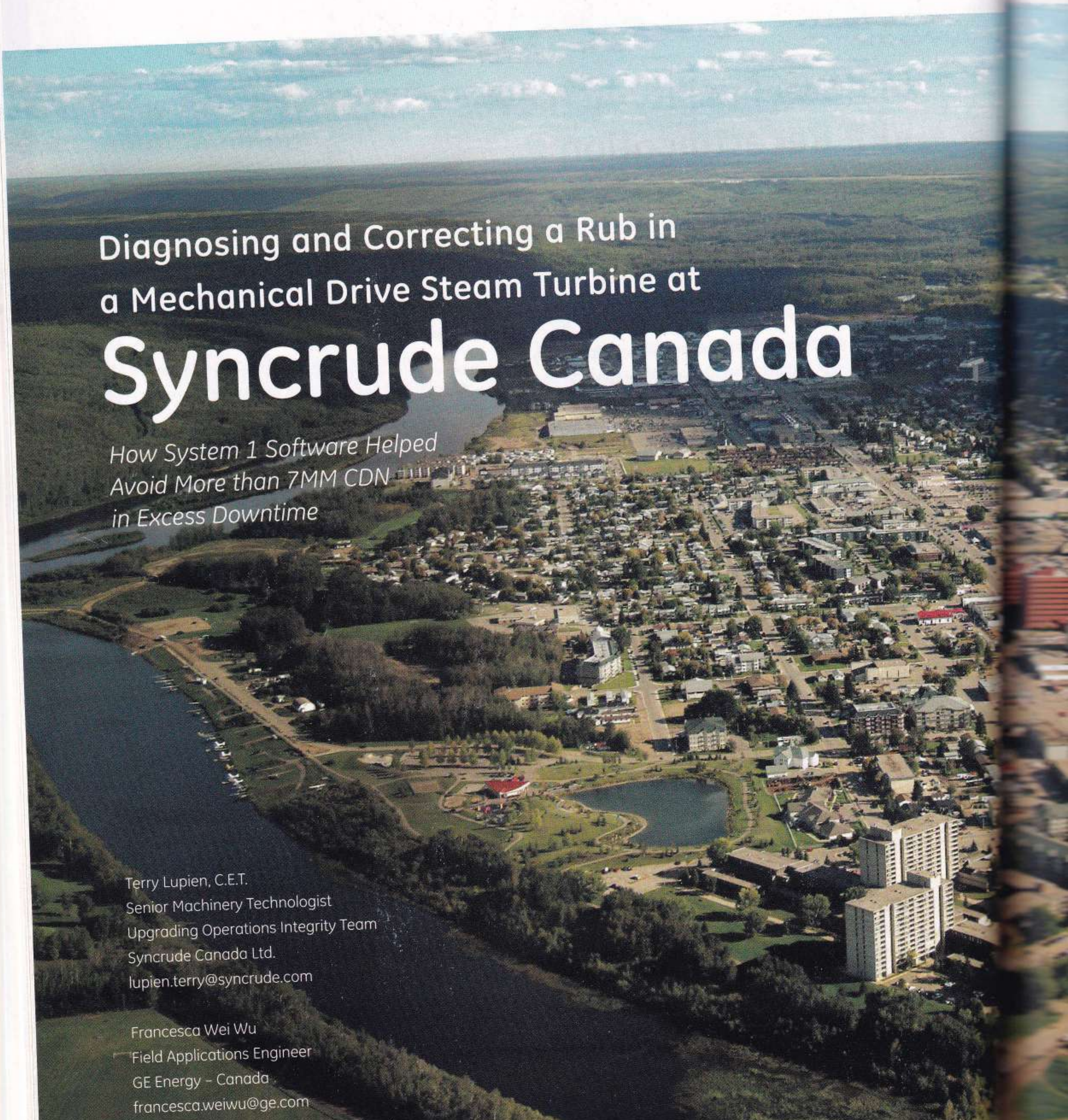
Suppliers can contribute to their customers' businesses in many ways. The most obvious is through the quality and value of the products and services they supply. But a supplier's reputation for health and safety can also be an increasingly important factor for customers. In an age of heightened scrutiny on corporate responsibility, shareholders and customers are today demanding more from their suppliers than just good prices, prompt delivery, profitable operation, responsive service, and quality products—they are demanding responsible citizenship as well. More than ever, there is little tolerance for suppliers that achieve cost and timeliness goals at the expense of community and employee health and safety.

VPP
Voluntary Protection Programs
An OSHA Cooperative Program

In a nutshell: poor corporate citizens reflect negatively on not just themselves, but their customers as well.

We're very pleased to announce that in July 2007, our Minden operations were re-certified by the Occupational Safety and Health Administration (OSHA) as a Voluntary Protection Program (VPP) STAR facility. VPP status is sought by companies that wish to communicate to their employees, customers, shareholders, and communities that they have moved beyond simply complying with applicable safety regulations and are engaged in additional, voluntary levels of proactive safety activities and awareness. As OSHA audits a facility, they look for several things: top management's commitment to health and safety, employee involvement in and awareness of safety programs and procedures, and ongoing hazard analysis and mitigation programs.

The majority of GE's Bently Nevada* products are produced at our Minden, Nevada, facility where more than 800 people come to work each day. As you use our Bently Nevada products and services, you can always be assured of our unyielding commitment to safety—for our customers, for our communities, and for ourselves.



Diagnosing and Correcting a Rub in a Mechanical Drive Steam Turbine at Syncrude Canada

How System 1 Software Helped Avoid More than 7MM CDN in Excess Downtime

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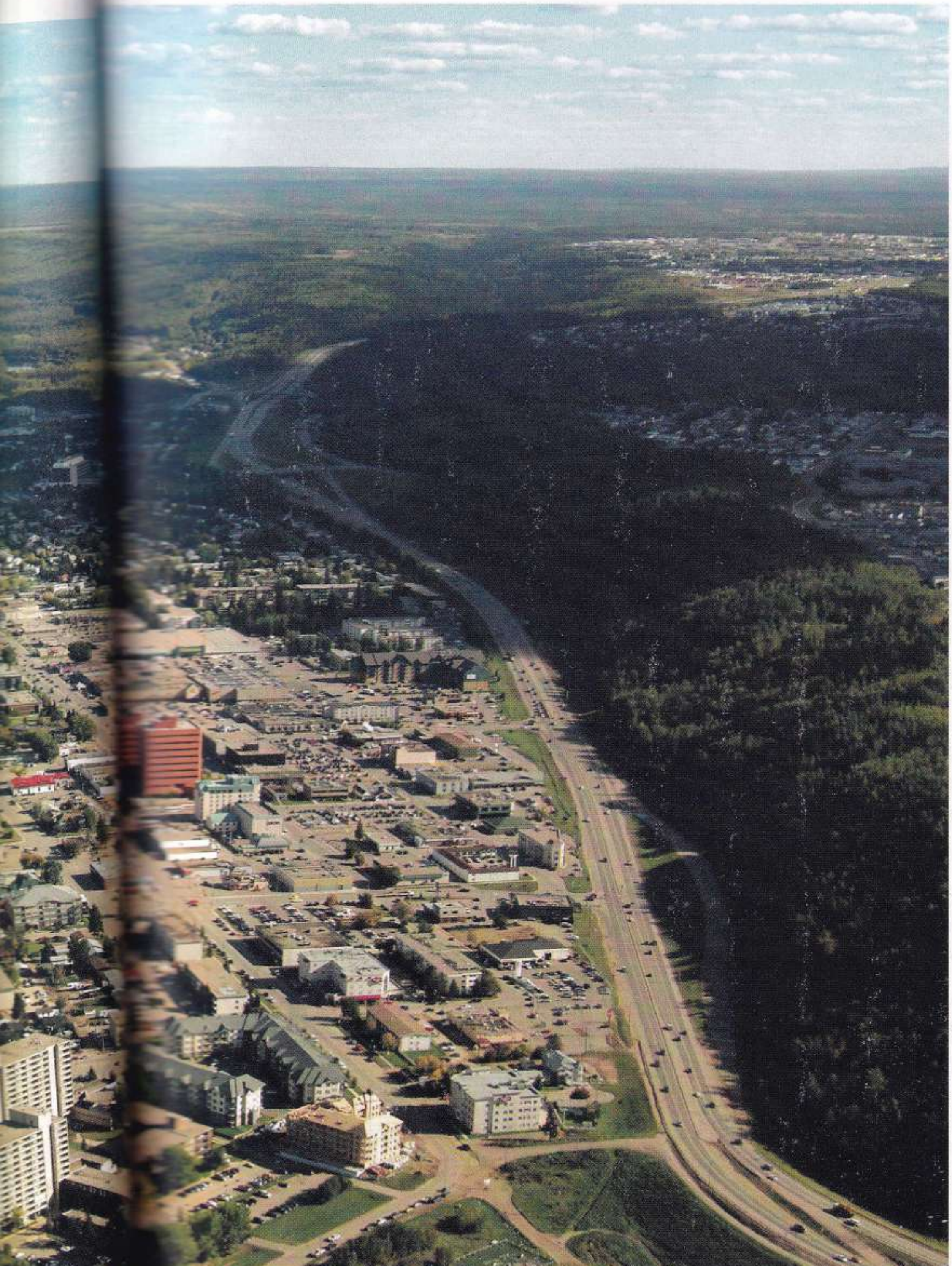


600 miles south of the Arctic Circle, along the banks of the Athabasca River and amidst one of Canada's many boreal forests, lies Fort McMurray, Alberta. The city is home to the more than 4,000 employees who work at Syncrude Canada's Mildred Lake operations, 25 miles to the north, extracting bitumen from the Athabasca Oil Sands deposit and converting it to synthetic crude oil. The mammoth Athabasca deposit is estimated to contain 1.7 trillion barrels of bitumen, of which nearly 500 billion barrels are ultimately recoverable using current and developing technologies.

Overview

This case history chronicles the efforts of Syncrude's Rotating Machinery Team in response to an upset condition on a mechanical drive steam turbine in one of three fluid coker units in the company's bitumen upgrading operations. It shows how GE's System 1* software was used to diagnose the problem and its severity, coordinating necessary inspection/repairs and ultimately isolating root cause. An estimated 24 hours of downtime was averted through the judicious use of this condition monitoring tool, saving more than $7MM in lost production at prevailing oil prices.

Oil Sands History

Although known for centuries to Canada's aboriginal peoples, the first documented European to see the Athabasca Oil Sands was a fur trader by the name of Peter Pond in 1778. Ten years later, famed explorer Alexander McKenzie made the following remarks in his journal:

"At about 24 miles from the fork (of the Athabasca and Clearwater Rivers) are some bituminous fountains into which a pole of 20 feet long may be inserted without the least resistance.

The bitumen is in a fluid state and when mixed with gum, the resinous substance collected from the spruce fir, it serves to gum the Indians' canoes. In its heated state it emits a smell like that of sea coal."

The deposits intrigued subsequent explorers, leading one to pen these prophetic words in 1889:

"That this region is stored with a substance of great economic value is beyond all doubt, and, when the hour of development comes, it will, I believe, prove to be one of the wonders of northern Canada."

By 1962, the Alberta government had released a policy for the orderly development of the oils sands deposits, and technological / commercial feasibility studies for extraction of the tar-like bitumen from the sands and conversion to synthetic crude oil began in earnest. In 1967, the first large-scale oil sands operation (Suncor) came onstream, followed in 1978 by Syncrude Canada Ltd. In the ensuing 20 years, Syncrude's production capacity has steadily increased and the plant is today the world's largest producer of crude oil from oil sands, supplying 15% of Canada's petroleum requirements while exporting its synthetic crude blend to refineries in the USA as well.

Syncrude Operations

Producing crude oil from oil sands combines the large-scale technologies of conventional open pit mining (the oil sands are covered by approximately 50 meters of overburden) with special extraction technologies that use steam to liberate the bitumen from the sand particles. The bitumen is then upgraded to a light, sweet, synthetic crude—known as Syncrude Sweet Blend (SSB)—in a 350 thousand barrel per day (kbpd) upgrading facility. The substantial power and steam requirements of these operational units are met through Syncrude's utilities plants, providing 350 MW of electrical generating capacity and nearly 450,000 kg/hr of high-pressure steam.

The Upgrading Area

The upgrading area (Figure 2) converts bitumen into synthetic crude by fluid coking, hydroprocessing, hydrotreating, and reblending. Three fluid cokers, along with an LC finer and one of the world's largest vacuum distillation units (Figure 3), convert the heavy bitumen into lighter cuts of hydrocarbons. The two original fluid cokers each have an air blower train with a steam turbine driving an axial flow blower to provide combustion and transport air, and an off-gas compressor train consisting of a multi-stage centrifugal compressor driven by a similar steam turbine.

The facility has machinery totaling approximately 400,000 horsepower and the continued performance of this equipment is entrusted to the Rotating Machinery Team. The team relies on condition monitoring systems to maintain close surveillance of all critical, un-spared machines. This helps the team align maintenance activities with planned outages, and make critical decisions as to when a situation calls for timely intervention.

Figure 2 – Syncrude's Upgrading Area.

Figure 3 – Syncrude's Vacuum Distilation Unit is one of the largest in the world.

Condition Monitoring Instrumentation

GE's Bently Nevada* monitoring systems have been used extensively in Syncrude's upgrading area since the early 1980s. The plant's condition monitoring capabilities have been systematically expanded and improved through periodic modernization programs, starting with 7200 series monitors when the plant was first built, moving to 3300 series systems during the Capacity Addition Project in the late 1980s, and then most recently to the 3500 series now in use across the area.

ADRE* 108 and 208 portable diagnostic systems have also been an effective part of the team's machinery diagnostic tools for years; however, the introduction of GE's System 1 software as an online machinery management platform for Syncrude provided new capabilities that could not be addressed with offline approaches to machinery management.

The condition monitoring system currently in use by Syncrude was installed during a compressor building upgrade in 2004/2005 where the machinery was fitted with Bently Nevada 3500 Series Machinery Protection Systems connected to System 1 software via a network. The system allows historical trending as well as full access to real-time and historical dynamic data such as vibration waveforms. System 1 software also supports the integration of process data from control systems with condition monitoring data. The ability to correlate machine and process data in a single user interface enables better analysis capabilities and a more focused response.

How these capabilities helped Syncrude's Rotating Machinery Team quickly identify and evaluate significant events and respond effectively was demonstrated during a subsequent upset condition in the upgrading area that occurred in early 2006.

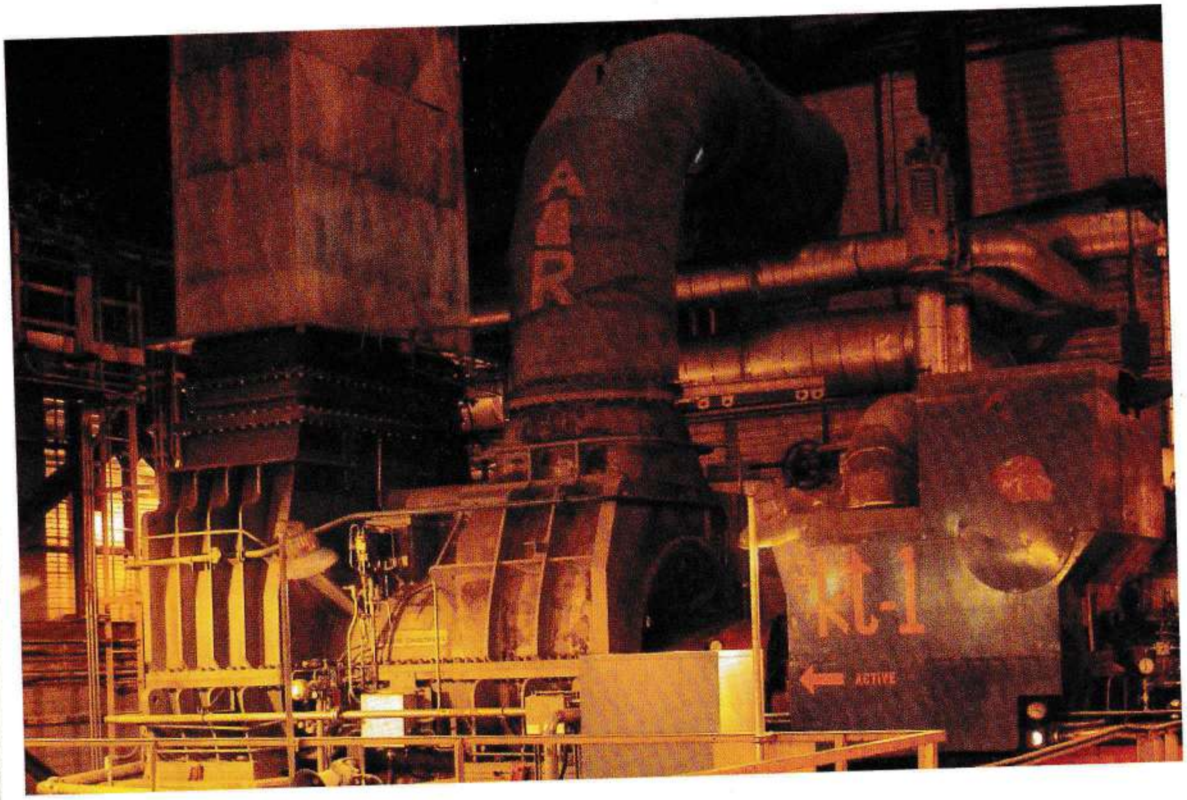
Machine Description

As part of a scheduled outage, the Unit 1 Coker Air Blower train was taken out of service in February, 2006. The air blower prime mover is a Westinghouse M-32 backpressure turbine (Figure 4) operating on 900 lb_f/in^2 supply steam and a 50 lb_f/in^2 exhaust header.

This turbine has very tight axial clearances in order to maintain higher efficiencies. The turbine construction uses centering beams to maintain the alignment of the bearing housings to the steam cylinder along the horizontal plane. This enables the steam cylinder to expand outwards from the centerline while keeping the shaft aligned to the cylinder. Vertical positioning is completed by having the cylinder mounted at its centerline to 'paws' on the support base that allow it to expand laterally outward from the centerline.

The governor end bearing (containing the thrust assembly for axial shaft location) is located to the base via "wobble legs" that allow for some movement. In order to maintain the tight axial clearances, a set of axial stay keys have been installed between the steam cylinder and the bearing housing to prevent it from tilting under high loads and opening up the axial clearances. The

Figure 4 - Unit 1 Coker Air Blower 8-1K1. The prime mover for this train is a back-pressure steam turbine, visible on the right of the photo and surrounded by scaffolding.



turbine shaft is sealed at the bearing housings with two types of labyrinth-style oil seals; bronze on the governor side and steel-fingered on the coupling side.

During the scheduled outage, the turbine bearings were inspected, clearances confirmed, and the thrust assembly checked. All oil seals were removed, cleaned, and reinstalled. Commissioning of the train was completed in April 2006 with normal run-ins and no deficiencies reported by the maintenance or process teams. Turbine vibration levels were measured in the 30 to 35 µm range, well within the normal operating parameters for this machine train.

Conditions Leading Up to Machine Trip

On May 2, 2006, after the unit had been returned to service, an oil seal leak was found on the governor side of the turbine. This condition required inspection to formulate a plan for control or repair. At the time, the machine train had been running at the same vibration levels as had been observed during the commissioning run-ins.

A steam hose was placed under the governor end of the machine to clean the area around the oil seal and facilitate a closer inspection of the leak. The hose was then moved near the centering beam to suppress smoke in the area. About 30 minutes after the steam lance made contact with the centering beam, a vibration excursion at the coupling end was detected by one of the operators, who in turn notified the Area Machinery Specialist. Circumstances pointed to the steam lance as the cause of the vibration excursion so the lance was repositioned a number of times and eventually turned off. However, this had little effect on the vibration.

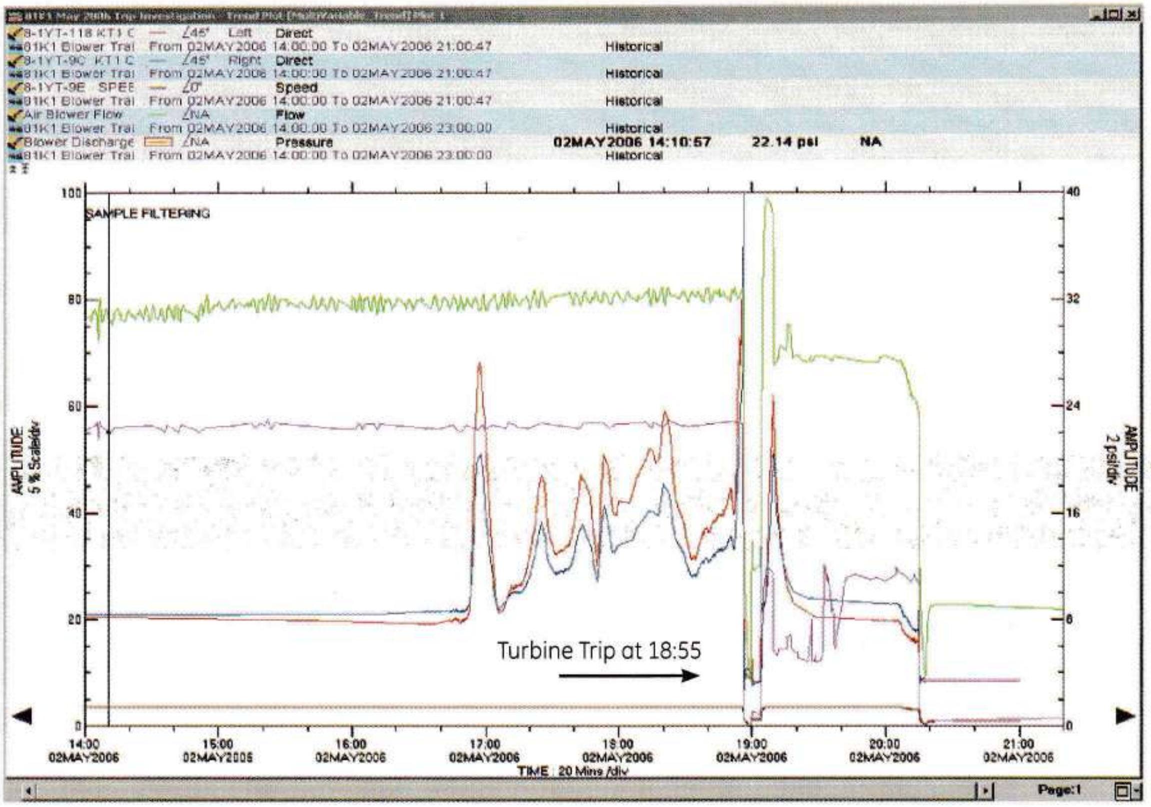


Figure 5 – Trends of turbine coupling-end vibration and process variables showing vibration excursions of X- and Y-probes (blue and red trend lines, respectively). Note that prior to the trip, turbine speed (brown), air blower flow (green), and blower discharge (purple) remained constant.

```
8-1YT-118 KT1 C   —  ∠45°  Left   Direct
81K1 Blower Trai  From 02MAY2006 14:00:00 To 02MAY2006 21:00:47          Historical
8-1YT-9C  KT1 C   —  ∠45°  Right  Direct
81K1 Blower Trai  From 02MAY2006 14:00:00 To 02MAY2006 21:00:47          Historical
8-1YT-9E  SPEE    —  ∠0°          Speed
81K1 Blower Trai  From 02MAY2006 14:00:00 To 02MAY2006 21:00:47          Historical
Air Blower Flow   —  ∠NA          Flow
01K1 Blower Trai  From 02MAY2006 14:00:00 To 02MAY2006 23:00:00          Historical
Blower Discharge  ▭  ∠NA          Pressure                  02MAY2006 14:10:57   22.14 psi   NA
81K1 Blower Trai  From 02MAY2006 14:00:00 To 02MAY2006 23:00:00          Historical
```

The team continued to monitor the vibration trend with particular attention to the coupling side of the turbine. The online monitoring and system integration capabilities of System 1 afforded the Rotating Machine Team several advantages:

- With System 1 software already in place and providing continuous condition information, valuable data for normal operation and shutdown that may have otherwise been missed (while having to set up a portable system) was captured and available for comparison and diagnosis.
- Imported process data was also directly available in the System 1 software, enabling the Area Machine Specialist to check for changes in process variables such as operating speeds and temperatures. Analysis of this data (Figure 5) showed no evidence of process changes, allowing the team to rule out process conditions as the cause of the vibration excursion, and to focus on mechanical factors.

Trip Event

At 18:55, a very high excursion on the coupling end of the turbine tripped the machine. During the coastdown period, the vibration level at the coupling end exceeded the full scale range of 150 µm on the 3500 vibration monitor as the turbine passed through its resonant speed range.

The turbine was quickly restarted to maintain air flow and prevent a larger downgrading incident. However, a totally unrelated problem with the anti-surge control system prevented full loading of the air blower. Given the situation at hand, the team made a critical decision to pull feed from the unit in an orderly manner and take the coker totally off line.

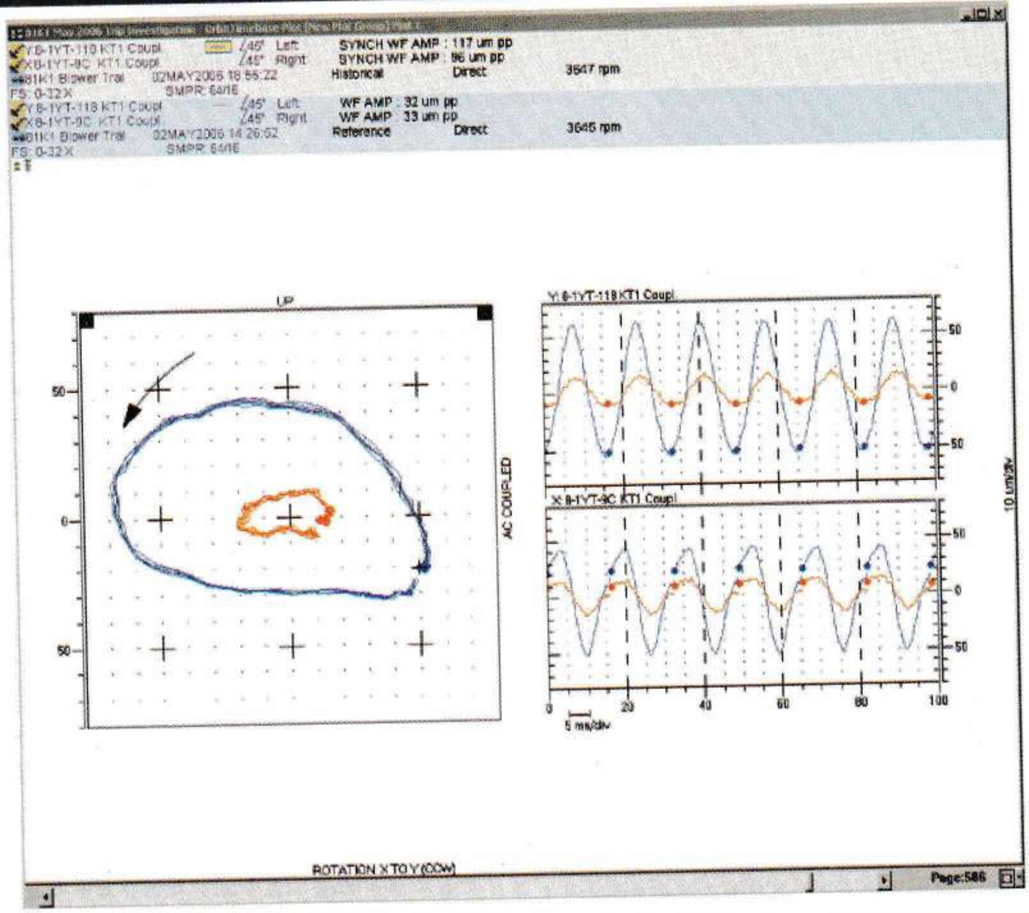
While the Instrumentation Team repaired the anti-surge control system, the Rotating Machinery Team reviewed the data from their System 1 software including orbits, trend plots, and spectrum plots. With additional data captured during the last vibration excursion and resultant trip, the team quickly ascertained the nature of the problem and pinpointed the areas in need of maintenance.

Diagnosis

One of the first things the team noticed was that during each vibration excursion, the turbine exhibited a high degree of "fluttering" axial movement that was not present during normal operation. Examination of radial vibration levels across the entire Air Blower train showed the coupling end of the turbine was the only location with a notable change prior to the trip.

A complete review of the orbit plots from the machine provided evidence that a rub was occurring at the coupling end of the turbine, eventually "locking in" and causing the vibration levels to exceed the danger alarm set point. The rub hypothesis was supported by data

Figure 6 – Orbit/timebase plot of vibration at turbine coupling end at running speed, just prior to trip. Orange indicates baseline data, blue indicates real-time data showing abnormally high vibration amplitudes.

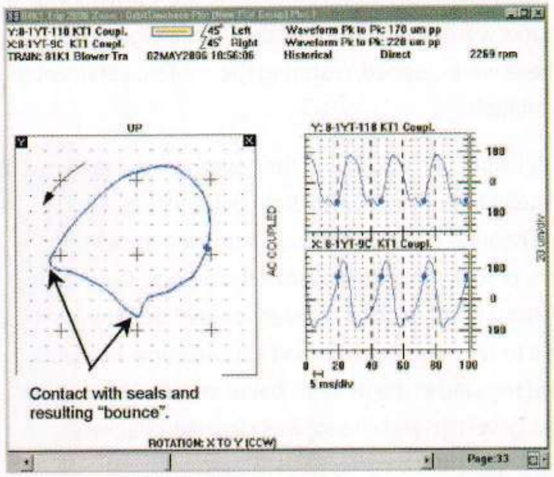


```
Y8-1YT-118 KT1 Coupl     ∠45° Left    SYNCH WF AMP : 117 um pp
X8-1YT-9C KT1 Coupl      ∠45° Right   SYNCH WF AMP : 96 um pp
81K1 Blower Trai   02MAY2006 18:55:22   Historical      Direct      3547 rpm
FS: 0-32X          SMPR: 64/16
Y8-1YT-118 KT1 Coupl     ∠45° Left    WF AMP : 32 um pp
X8-1YT-9C KT1 Coupl      ∠45° Right   WF AMP : 33 um pp
81K1 Blower Trai   02MAY2006 14:26:52   Reference       Direct      3645 rpm
FS: 0-32X          SMPR: 64/16
```

indicating the vibration level increased during the coastdown through the first resonance, and by the shape of the orbits (Figures 6 and 7).

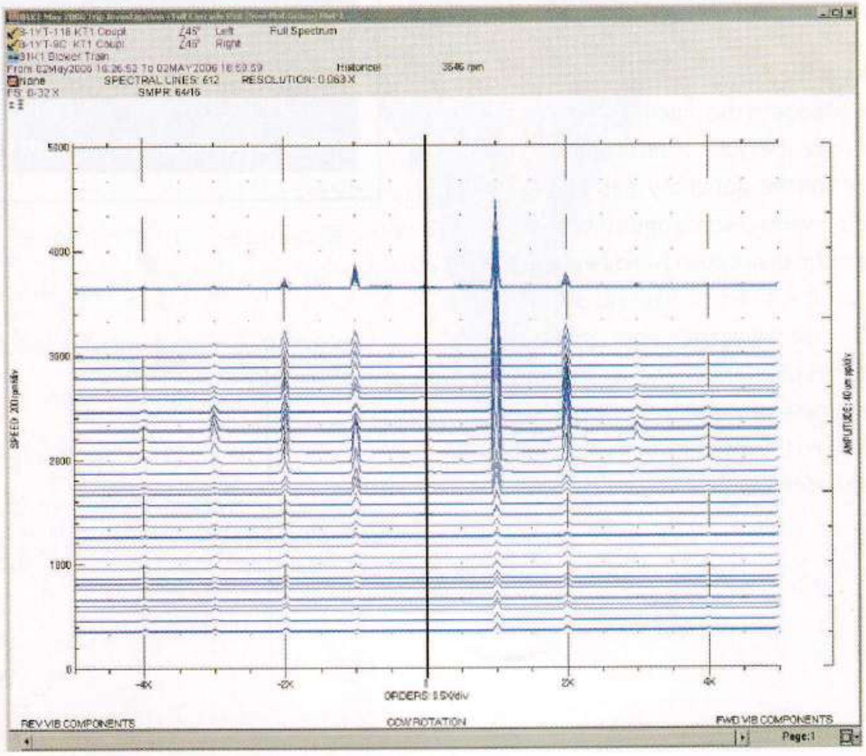
The direct and 1X trend plots provided further validation that this was indeed a rub situation. Virtually all shaft movement was composed of 1X (shaft rotative speed) vibration frequencies as noted in the full spectrum cascade plot of Figure 8. Even as the turbine coasted down, the vibration remained with a predominant 1X component. The vibration all but disappeared once the machine dropped below a certain speed, but at which residual unbalance would have still been noticeable. This abrupt speed-related absence of vibration suggested that the problem was not a balance-related phenomenon.

Figure 7 – Orbit/timebase plot of vibration at turbine coupling end during coastdown following trip as unit passes through first resonance speed. Note flattened shape of orbit, indicative of severe rubbing.



Y:8-1YT-118 KT1 Coupl. ∠45° Left Waveform Pk to Pk: 170 um pp
X:8-1YT-9C KT1 Coupl. ∠45° Right Waveform Pk to Pk: 228 um pp
TRAIN: 81K1 Blower Tra 02MAY2006 18:56:06 Historical Direct 2269 rpm

Figure 8 – Full cascade spectrum of turbine coupling end during coast down. Note that vibration is primarily at 1X frequency component and abruptly disappears for machine speeds below approximately 1800 RPM.



8-1YT-118 KT1 Coupl ∠45° Left Full Spectrum
8-1YT-9C KT1 Coupl ∠45° Right
81K1 Blower Train
From 02May2006 16:26:52 To 02MAY2006 18:59:59 Historical 3546 rpm
none SPECTRAL LINES: 612 RESOLUTION: 0.063 X
FS: 0-32 X SMPR: 64/16

Confident in their diagnosis, the team formulated a plan to inspect the coupling-end oil seals and correct the leaking governor-end oil seal. The inspection showed the oil seal on the turbine side of the coupling-end bearing housing had indeed sustained a very hard rub (Figure 9A), necessitating maintenance. Corresponding marks were found on the turbine shaft (Figure 9B). These were cleaned, restoring the shaft to serviceable condition.

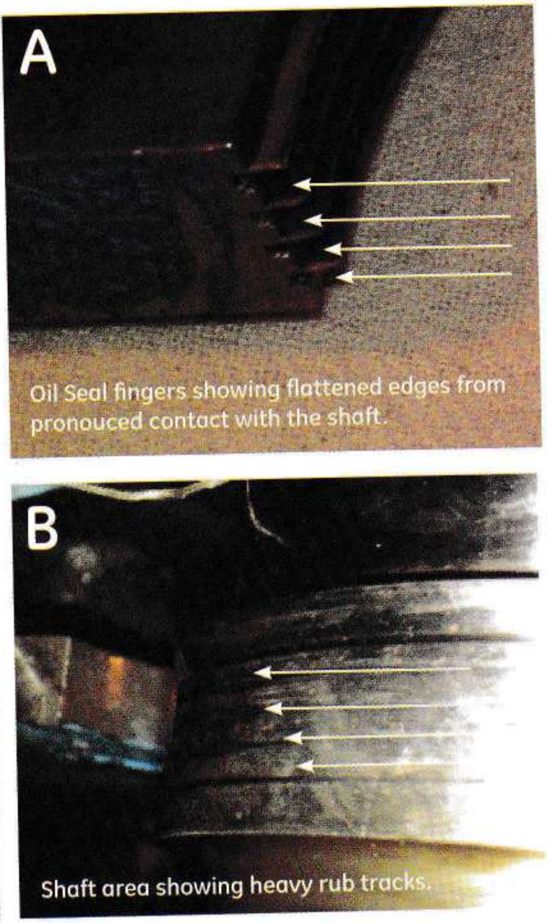
The inspection also found the governor-end oil seal was installed incorrectly, with drain holes facing outside the bearing housing instead of draining back inside. This proved to be the cause of the oil leak. During the original maintenance, different oil seal designs used on this turbine and its sister unit caused some confusion and resulted in the oil seals being installed backwards. The governor-end oil seal was cleaned, checked, and reinstalled in the correct orientation.

Following this maintenance, there were no more problems with vibration and all pertinent measurements returned to normal operating levels

Root Cause Determination

Based on analysis of the data provided by System 1 software and knowledge of the machine's history, the trip was deemed to be the result of an alignment change between the rotor and the stationary diaphragms that caused the rotor to move upwards and contact the turbine-side oil seal on the coupling-end bearing. This contact created a rub, resulting in high vibration. The root cause of the incident was the steam lance which was placed in various positions on the supporting structure for the turbine, resulting in thermal growth changes which altered the machine's internal alignment and reduced clearances enough to cause contact.

Figure 9 – Rub damage on seal (A) and shaft (B).



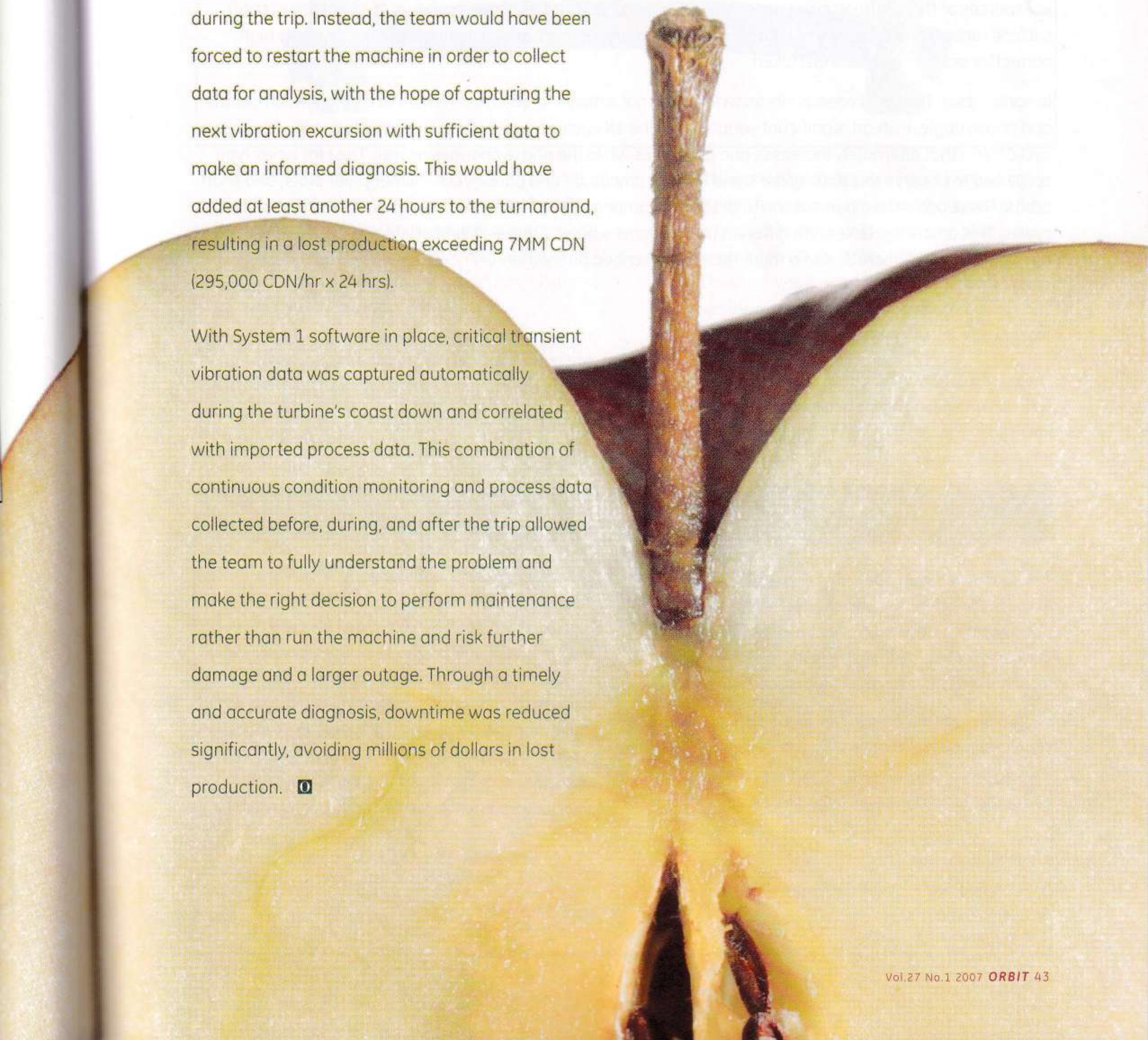
Oil Seal fingers showing flattened edges from pronouced contact with the shaft.

Shaft area showing heavy rub tracks.

Summary

Prior to the latest modernization program and the installation of System 1 software, online systems were not in place and the team had to rely exclusively on the use of portable ADRE* systems. Data would thus not have been captured automatically during the trip. Instead, the team would have been forced to restart the machine in order to collect data for analysis, with the hope of capturing the next vibration excursion with sufficient data to make an informed diagnosis. This would have added at least another 24 hours to the turnaround, resulting in a lost production exceeding 7MM CDN (295,000 CDN/hr x 24 hrs).

With System 1 software in place, critical transient vibration data was captured automatically during the turbine's coast down and correlated with imported process data. This combination of continuous condition monitoring and process data collected before, during, and after the trip allowed the team to fully understand the problem and make the right decision to perform maintenance rather than run the machine and risk further damage and a larger outage. Through a timely and accurate diagnosis, downtime was reduced significantly, avoiding millions of dollars in lost production.



The Morton Effect

and Light Rubs in Rotating Machinery

Synchronous (1X) vibration is typically present on all types of rotating machinery. Common causes or sources of this vibration component include mass unbalance, mechanical bows, thermal bows, shaft surface runout, and rubs. When vibration levels from one of these sources becomes unacceptably high, corrective action must be undertaken.

In some cases, the synchronous vibration levels do not simply increase and remain at a constant amplitude and phase angle. Instead, significant variations of the 1X vectors occur where the amplitude may assume a cyclic trend that alternately increases and decreases while the phase changes as well. The plot types typically used to observe this activity are trend files (1X amplitude and phase versus time), polar plots, and shaft orbits. These allow the diagnostician to determine, among other things, the magnitude and period of the cycles. This article discusses two different mechanisms whereby these 1X amplitude and phase variations can be observed: light rubs and a more recently described phenomenon known as the Morton Effect.

Mechanism #1 – Light Rubs

There are a variety of rubs that can occur in machinery, with different rub locations (seals, bearings, etc.), different initiating conditions, and different rub classifications (full annular, partial, bouncing, etc.). Here, we confine our discussion to light rubs that create a thermal bow condition. It is these types of rubs that often result in a modulating synchronous vibration response.

The friction caused by light rubbing on a rotor gives rise to localized heating (a so-called rotor "hot spot") that is not uniformly distributed around the shaft circumference. This causes the shaft to expand longitudinally in a non-uniform manner, resulting in a bow (Figure 1).

While one might reasonably conclude that the ensuing shaft bow acts as a positive feedback mechanism, causing the rotor to rub even more, heat up even more, and subsequently bow even more, there is actually another mechanism at work in the case of light rubbing that counteracts this. In practice, the conditions that gave rise to the initial rub are frequently related to loading conditions, such as partial load operation, transient changes in load, or operation at higher-than-normal capacities. As a result of the loading, thermal distortion occurs in the machine and a rub ensues. However, as the load changes or the machine assumes thermal equilibrium in the new load condition, clearances open, and the rub stops. The rotor hot spot then cools, the bow relaxes, and the vibration decreases. When the load changes again, a rub is initiated and the cycle repeats itself. In such situations, the amplitude trend will exhibit a cyclic increasing/decreasing behavior. If the rub initiating mechanism is somewhat periodic, as in a load change that occurs at regular intervals, the periodicity in the amplitude trend may be regular as well. In cases where the initiating mechanism is not periodic, the amplitude trend will show variations, but there will be

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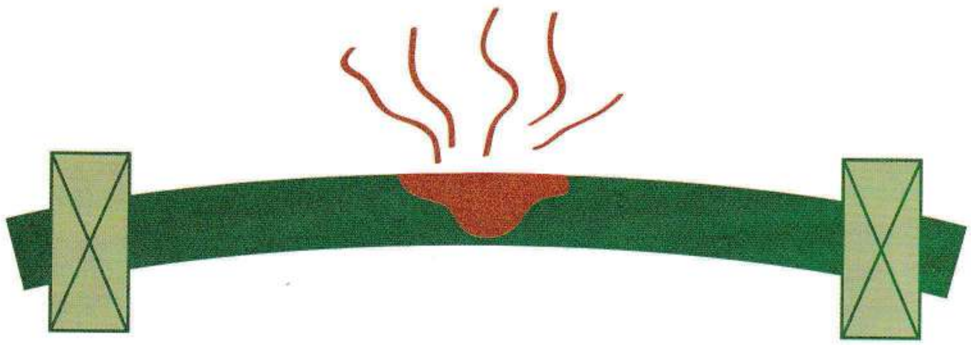
Figure 1 – Rubbing results in localized hot spots on the rotor where contact is occurring. This causes one side of the rotor to expand longitudinally more than the other, resulting in rotor bow.

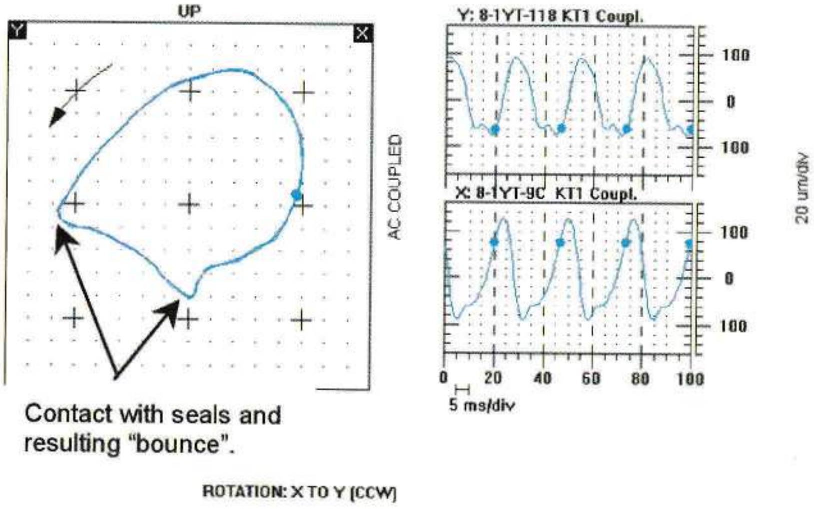


no repeatable periodicity. However, the diagnostician must use caution because the response from the rub mechanism is highly non-linear and periodicity may not always be readily observable, even when the initiating mechanism itself is highly regular. This is discussed in more detail later in this article.

Several diagnostic plots are useful when diagnosing a rub. Chief among these is the shaft orbit plot. Although not always the case, shaft orbit presentations can give quite dramatic indication of a rub as evidenced by flat spots on portions of the orbit where contact is occurring and orbital motion is constrained. Figure 2 shows an orbit obtained from a machine experiencing a seal rub. One can readily see the portion of the orbit where the rub is occurring as the shaft "bounces" away from the contact location. Visual examination of the seals later confirmed the diagnosis, as rub tracks were evident on both the shaft and the seal.

[Editor's Note: If Figure 2 looks familiar, that's because it also appears in the case history on pages 34–43 in this issue of ORBIT. Please refer to that article for photographs of both the shaft and seal surfaces, which were taken during visual inspection to confirm that a rub was indeed occurring.]

Figure 2 – Shaft orbit plot from a mechanical drive steam turbine experiencing a seal rub.

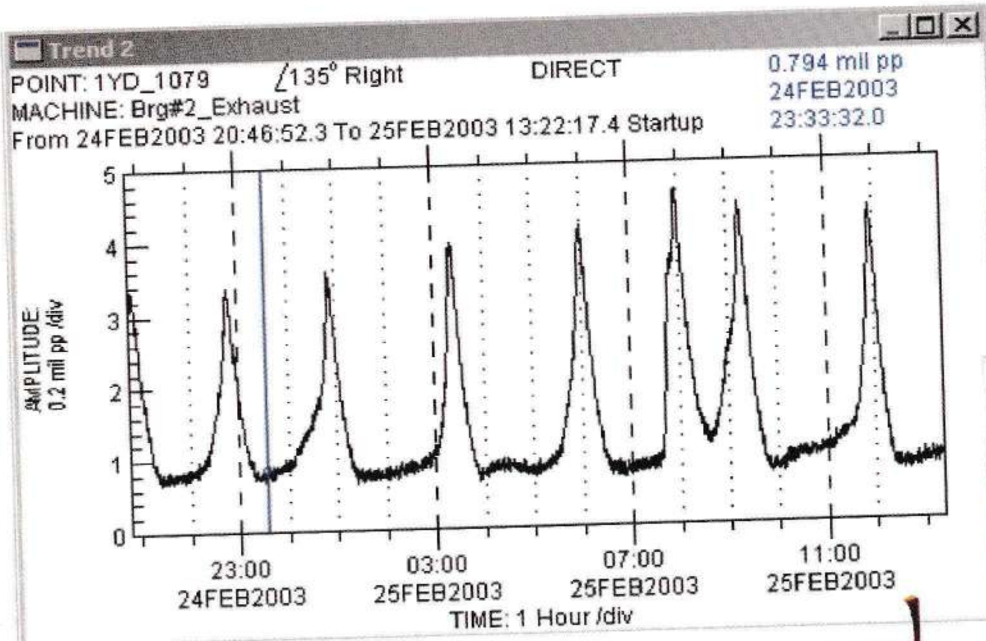


While rubbing conditions will sometimes be readily apparent from the shaft orbit plots, particularly for moderate to heavy rubs, the indications in the orbit from light rub conditions may be more subtle. Other plot types are thus useful.

A multivariable trend plot that allows the diagnostician to examine vibration amplitude and load conditions simultaneously can be particularly helpful when it is suspected that a rub is occurring and is being initiated by load conditions. Correlations between amplitude (and phase) changes and load changes can be easily observed using this plot type. If an increase in vibration is always accompanied by a transient change in load conditions, or occurs only when the machine is in certain load conditions (such as partial load), a light rub and corresponding thermal bow is a strong possibility.

Figure 3 was obtained during a field machinery diagnostics job conducted by the author and shows the amplitude trend plot collected from a gas turbine experiencing a light rub during steady-state base load conditions. The trend plot shows the classic cyclic behavior discussed earlier, where the amplitude alternately increases and then decreases. In this instance, however, the rub-initiating mechanism turned out to be unrelated to load. It was found that the machine had a leaky oil seal. As the oil leaked, it would slowly heat until it became hardened (i.e., formed coke) and continue to build up until a rub ensued. The coke would be abraded away through the rubbing action until the rub disappeared, but the leaking oil would form more coke and the cycle would repeat itself.

Figure 3 – Trend plot showing cyclic amplitude oscillations resulting from a light rub. The vibration reaches a peak approximately every 2-3 hours and then temporarily subsides again.


Trend 2

POINT: 1YD_1079 ∠135° Right DIRECT

MACHINE: Brg#2_Exhaust

From 24FEB2003 20:46:52.3 To 25FEB2003 13:22:17.4 Startup

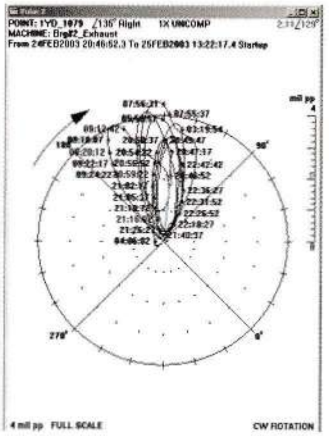
0.794 mil pp
24FEB2003
23:33:32.0

Because rub is a non-linear response mechanism, it is important to note that changes in phase and amplitude may not be repeatable from one cycle of the oscillation to the next. The rub may be more severe, less severe, or absent entirely—as can be the case when the rub has sufficiently eroded the contacting locations to permanently alter clearances. Nor will the peaks and valleys of the amplitude trends be perfectly periodic, even if the initiating conditions (such as load changes) are themselves perfectly periodic.

The polar plot of Figure 4 illustrates this non-linearity quite dramatically and is taken from the same machine and proximity probe as the trend plot of Figure 3. The "loops" in the polar plot are indicative of changes in both amplitude and phase, but notice that these changes do not "retrace" themselves from one cycle to the next.

[Editor's Note: Why does a light rub result in not just amplitude changes, but continually changing phase as well? The answer to this question will appear in the next issue of ORBIT magazine.]

Figure 4 – Polar plot from the same probe location as Figure 3, showing non-linear (non-repeatable) vibration and phase response. Such response is typical of a light rub.



Mechanism #2 – Journal Thermal Gradients (Morton Effect)

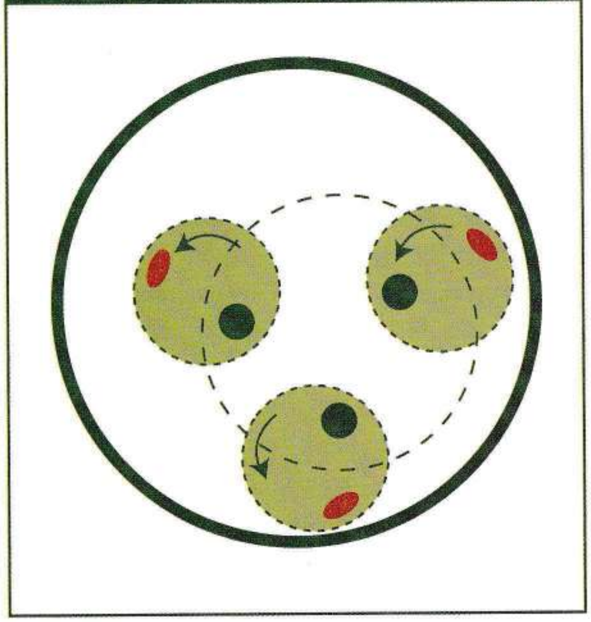
Another phenomenon can occur in rotating machinery and give data similar to that resulting from a light rub. Inspection of the machinery affected by this condition will show that no rub is in fact occurring. Instead, it has been postulated that temperature gradients ("hot spots") occur on the shaft's journal surface as the result of high viscous shear stress in the bearing lubricant. Consequently, the shaft bows just as if a hot spot occurred from a rub, and a very similar vibration response is observed.

This mechanism was first described in a 1994 paper by P.S. Keogh and P.G. Morton, and has subsequently become known as the "Morton Effect". It generally occurs only under very specific conditions; in particular, on machines incorporating an overhung rotor design and which are heavily loaded. Here, only a brief overview of the so-called Morton Effect is provided so the reader can be familiar with the phenomenon should it be encountered in practice. The reader is strongly encouraged to obtain additional information on the Morton Effect and its underlying hypotheses using the references at the end of this article.

To understand how the Morton Effect occurs, refer to Figure 5. Here, it is assumed that the dominant force acting on the machine is residual unbalance, and that the bearing stiffness is symmetrical about the centerline. This results in predominantly synchronous (1X) vibration with a largely circular orbit as the shaft vibrates within its bearing clearance. Vibration of this form orients the rotor surface in the same position each time it rotates as long as loading and speed remain constant. This means that the same segment of the rotor's circumference will always be subject to the minimum clearance (the red spot on the rotor in Figure 5) while another segment of the rotor's circumference will always be subject to the maximum clearance (the black spot on the rotor in Figure 5). Although this condition creates a thermal gradient instead of a uniform heat distribution about the rotor's circumference, unless the shear stresses are suitably large, the gradient will not be large enough to result in a shaft bow. However, when the shear stresses are sufficiently large, the heating effect is appreciable and the shaft bows, just as if a rub was occurring at the location of minimum oil film thickness. As a result, the 1X vibration amplitude increases.

As the effect (i.e., a hot spot on the shaft) of this mechanism is quite similar to that of a light rub, it is not surprising that the vibration response may be quite similar as well. However, because the Morton Effect occurs inside the bearing area where lubricant is present to provide cooling, the thermal rate of change tends to be more linear than that which occurs under true rub conditions. As such, the vibration pattern is more repeatable from cycle to cycle and typically results in a polar plot with one of two distinct patterns:

Figure 5 – The Morton Effect. Under certain conditions, the shear stresses in the bearing lubricant can be sufficiently large to create localized heating on the rotor, causing it to bow.



1. Repeating Loops

When the machine is under highly steady-state conditions without even minor variations in speed or load, the shaft attitude angle (i.e., location of the shaft on the supporting oil-film wedge in the bearing) remains highly steady as well. Consequently, the "hot spot" on the shaft remains in the same location. As the machine undergoes its cyclic changes in amplitude and phase due to the repetitions of the shaft bowing and then relaxing, the stationery location of the hot spot results in changes in amplitude and phase that are so repeatable as to trace nearly the same pattern on the polar plot from one cycle to the next. This is shown in Figure 6. Compare this response with the non-linearity (non-repeatability) of the response for an actual light rub condition as shown in Figure 4.

2. "Spiral" Vibration

When the machine is experiencing small fluctations in speed and/or load, the shaft attitude angle will experience small changes as well, causing the shaft hot spot to shift slightly. This moving hot spot gives rise to spiral pattern in the polar plot as the shaft bows and relaxes cyclically. Figure 7 shows a polar plot from the same proximity probe as Figure 6, but with the machine undergoing slight changes in speed/load. Now, the loops no longer exactly retrace themselves, but instead appear as expanding/contracting spirals.

Although the Morton Effect is far less common than light rubbing in machinery, there are certain indications that can lead the diagnostician to suspect this mechanism when other, more common, malfunctions have been ruled out:

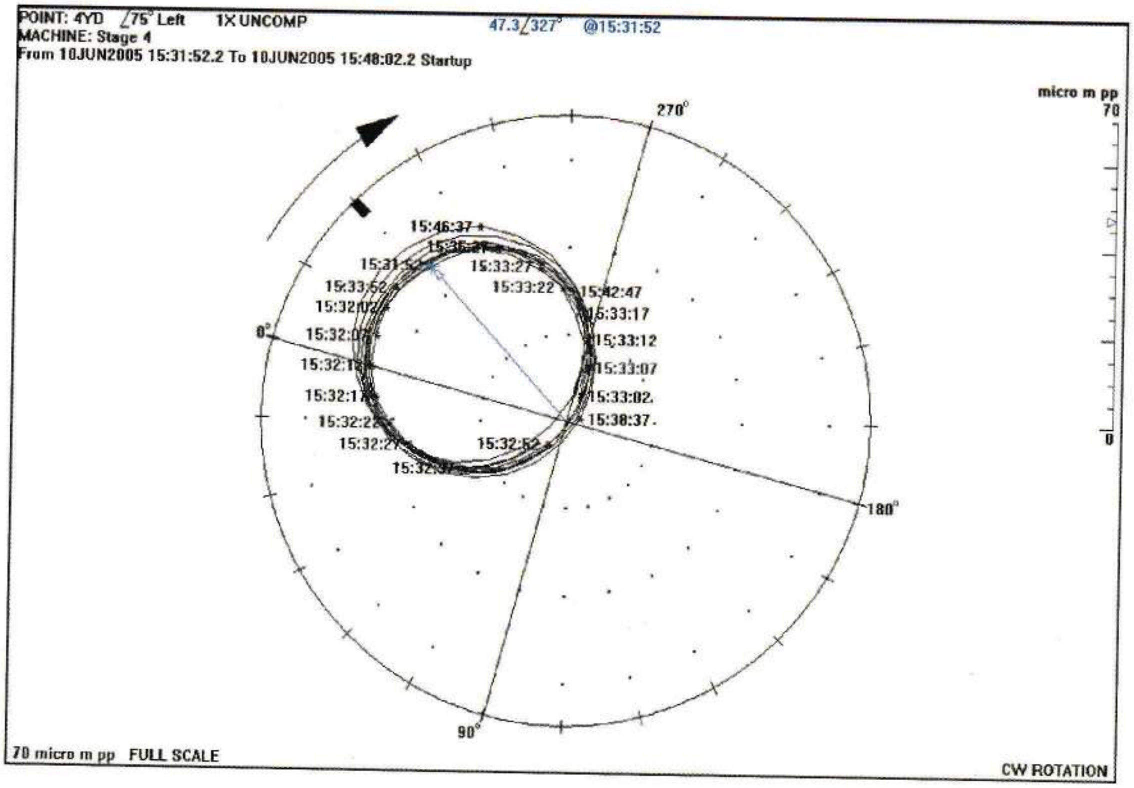
A. When the machine under investigation incorporates an overhung design and is heavily loaded.

B. When the 1X amplitude and phase variations appear to be quite repeatable and smooth from one cycle to the next—far more repeatable than would be expected from a rub. These will appear either as re-traced loops (Figure 6) or as spirals (Figure 7).

C. When visual inspection of the machine gives no evidence of a rub.

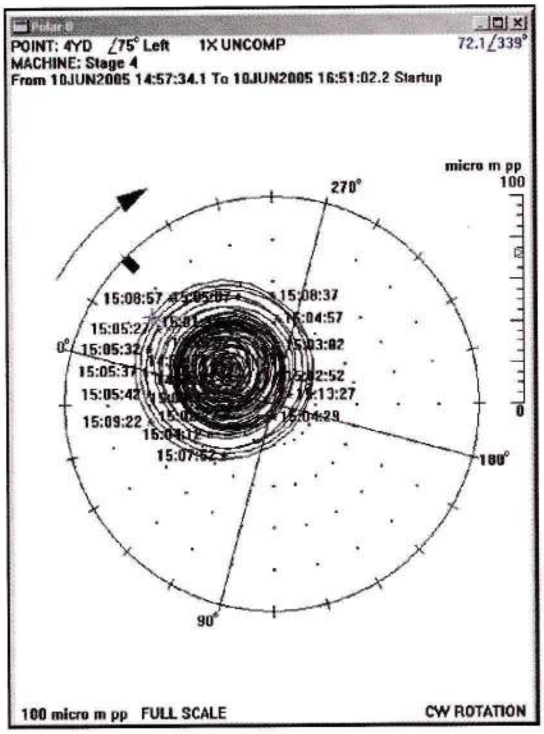
D. When changes in the lube oil temperature affect the cyclic vibration periodicity and amplitude.

Figure 6 – Polar plot showing evidence of the Morton Effect as noted by the highly repeatable changes in amplitude and phase during each limit cycle.



"ALTHOUGH THE MORTON EFFECT IS FAR LESS COMMON THAN LIGHT RUBBING IN MACHINERY, THERE ARE CERTAIN INDICATIONS THAT CAN LEAD THE DIAGNOSTICIAN TO SUSPECT THIS MECHANISM WHEN OTHER, MORE COMMON, MALFUNCTIONS HAVE BEEN RULED OUT."

Figure 7 – Polar plot of same probe as Figure 6, but with machine undergoing slight variations in speed/load, leading to spiral vibration patterns rather than the repeatable looping of Figure 6.



POINT: 4YD ∠75° Left 1X UNCOMP 72.1∠339°
MACHINE: Stage 4
From 10JUN2005 14:57:34.1 To 10JUN2005 16:51:02.2 Startup

As part of the machinery diagnostics job carried out by the author on the machine used for Figures 6 and 7, criteria A, B, and D were met. Both repeatable loops and spiral vibration patterns were observed in polar plots from the machine, depending on speed fluctuations and loading conditions. Changes to the lube oil temperature were conducted and corresponding changes to the amplitude and periodicity of the magnitude trend was observed. The machine was reasonably heavily loaded. And, the machine was an integrally geared air compressor where the impeller was overhung from a high-speed pinion. Combined, these factors pointed strongly towards the Morton Effect as the underlying cause of the elevated vibration levels. The operator was advised to avoid certain lube oil temp ranges and machine loading conditions until a more permanent remedy could be applied.

Summary

Light rubs are commonly encountered in rotating machinery and often give rise to a distinct, cyclical pattern in amplitude and phase trend plots, as well as polar plots. Shaft orbit plots are likewise valuable as they may give direct evidence of more pronounced rubs, observable as flat spots where motion is constrained or "bumps" where the shaft actually bounces against a stationery surface such as a seal. The Morton Effect yields data similar to a rub because the underlying mechanism (localized heating) is the same.

However, in the case of a rub, the heating occurs due to mechanical friction as rotating and stationary parts contact one another, while in the case of the Morton Effect, the heating occurs as the result of excessive shear stresses in the lubricant. This article has provided an introductory overview of the Morton Effect and shown the ways in which polar plots may be used to differentiate this phenomenon from that of a true rub condition.

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Considerations When Using Extended Field Wiring Lengths with Bently Nevada Transducers

[Editor's Note: This article is an abbreviated version of Bently Nevada Applications Note 178454. Due to space limitations, all available graphs, tables, and sample calculations have not been reprinted here from that Note. The interested reader is encouraged to download the full Note from the electronic version of our Reader Service Card for this issue of ORBIT, available at www.orbit-magazine.com.]

The standard maximum cable run for Bently Nevada* transducers has been specified for many years in our product manuals and datasheets as 1000 feet (305 meters). In some cases, however, users have found this limitation to be inconvenient and are interested in running field wiring over extended distances to suit their needs. Longer lengths can be accomplished, provided the user understands the engineering principles involved and is able to properly quantify the effects of longer cable lengths and assess the impact on their particular application. This article discusses the key issues with extended field wiring by showing how wiring length and construction effects capacitance and frequency response, by discussing the types of applications that are particularly dependent upon high-frequency signal content, and by discussing the concept of capacitance limits and its relationship to hazardous area installation requirements.

The origin of the 1000 foot limit

For many years, the field wiring for Bently Nevada transducers has been recommended as 18 AWG. Depending on the transducer type, either 2-conductor or 3-conductor cable is used. Although lighter gauges can also be used (such as 22 AWG), experience has shown that lighter gauges have a greater tendency to break when connecting to terminals on the monitor and transducer. One of the limitations inherent with heavier gauge wire is that it represents greater capacitance per unit length, which in turn affects both the frequency response and suitability for hazardous areas where strict limits on total circuit capacitance are in effect.

Thus, along with our recommendation for 18 AWG wire came a recommendation to limit the length to no more than 1000 feet (305 m) in non-hazardous areas. This length was chosen both because it is easy to remember and because it introduces only minimal signal degradation, allowing the full 10 kHz frequency response of our typical transducers to pass with little attenuation. However, as will be discussed in this article, this limit does not hold for all applications. Hazardous area applications and/or those for which the frequency response requirements differ from 0–10 kHz will require the designer to carefully consider the field wiring's effects on stored energy and signal attenuation. This article, and its companion Applications Note, serve as primers on the subject, familiarizing installation designers with the engineering considerations and calculations involved.

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Cable Capacitance

The frequency response of cable is affected by resistance, capacitance, and inductance. However, capacitance will usually be the first to cause problems. In addition, installations into areas with hazardous classifications usually limit the capacitive load allowed. In either case, the total cable capacitance must be calculated and evaluated against the pertinent limits.

The total cable capacitance is a function of the following factors:

- Cable Length
- Number of Conductors
  In most cases, field wiring will have two or three conductors, depending upon the type of transducer being used. Proximity transducers always use a three-conductor system (power, signal, common) while other transducers either may not require external power or may share the power/signal wire; consequently, they use a two-conductor system.
- Cable Specifications
  The relevant values for field wiring analysis are the cable capacitance per unit length and the total capacitive load. The data sheet for cable will typically lists its capacitance per unit length. If you cannot find this value, you can usually calculate it from other datasheet values as explained below.

Capacitance values for the field wiring provided by GE for use with Bently Nevada transducers are shown in Table 1.

Table 1 – Cable Capacitance for field wiring provided by GE for use with Bently Nevada transducers

Part Number	Description	Capacitance
02173006	18 AWG two-conductor cable	98 pF/meter
02120015	18 AWG three-conductor cable	289 pF/meter

When using cable from another supplier, consult their datasheet or contact the manufacturer to obtain capacitive values. When this is not possible or practical, it will be necessary to determine these values yourself using the following equations:

- **For two-wire circuits**
  Total capacitance = capacitance core to core + capacitance core to screen.
  $C_{\text{total}} = C_{\text{core-to-core}} + C_{\text{core-to-screen}}$
- **For three-wire circuits**
  Total capacitance = (2 X capacitance core to core) + capacitance core to screen.
  $C_{\text{total}} = (2^{*}C_{\text{core-to-core}}) + C_{\text{core-to-screen}}$

The goal is to determine the total capacitive load for a given length of cable. To find this, multiply the cable capacitance per unit length by the total cable length. As has previously been noted, this total capacitive load must be taken into account when considering the hazardous area and signal integrity issues.

Specific installations often run field wiring cable with lower capacitance than that offered by GE to mitigate long field wire lengths. This is successful when proper engineering practices are applied to quantify the performance.

Applications

Certain applications and measurements are known to generate high-frequency content and are particularly dependent upon field wiring that preserves the full spectral integrity of the signal. This typically occurs when the machine itself runs at very high rotational speeds and/or when the nature of the vibration tends to generate a number of harmonics. Some common applications and their dependence upon high-frequency signal content are noted below.

- **Applications more dependent upon high-frequency signals**

  Gearboxes, turbine blade pass, rolling element bearing signatures, high-speed machines (e.g., turbo expanders and the high speed stages of centrifugal air compressors), speed-sensing applications with the sensor observing a toothed wheel.

- **Applications less dependent upon high-frequency signals**

  Non-vibration measurements (e.g., thrust position, differential expansion, case expansion), low-speed machines (e.g., hydro turbine/generators, reciprocating compressors).

The above is intended only as a general guideline. Each application must be evaluated on its own merits by considering the construction of the machine, the frequencies it is likely to generate under normal operating conditions (blade pass, gear mesh, ball pass, etc.) and the frequencies it is likely to generate under malfunction conditions (cavitation, structural resonances, rough load zone, etc.).

Signal Quality

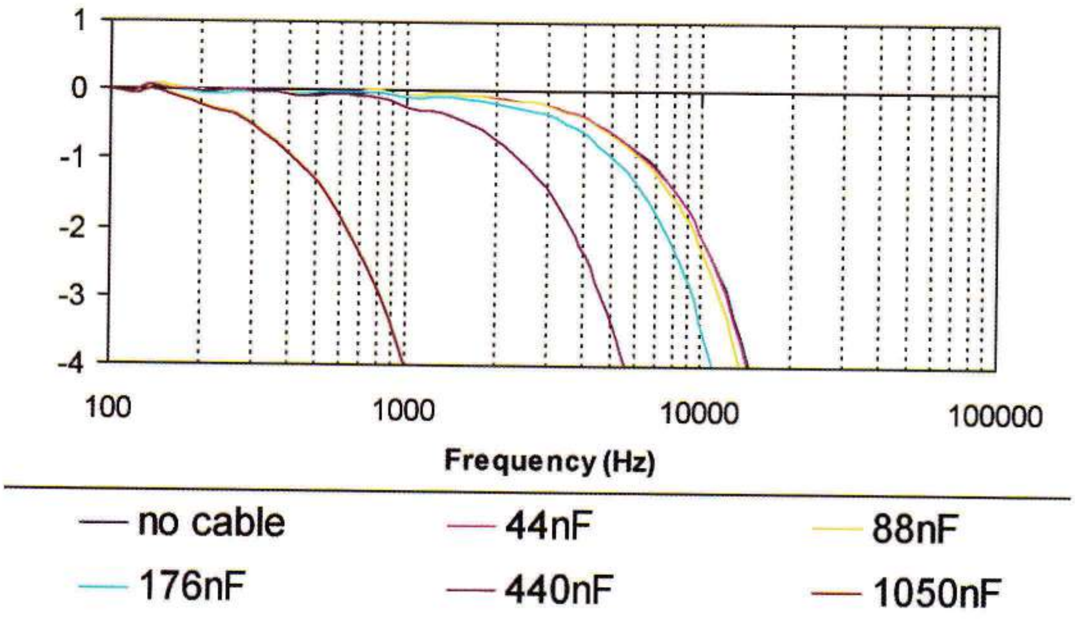
Driving a large capacitive load can be problematic as large loads can attenuate higher frequencies. What is considered 'too large' will depend of the type of transducer being used and the frequencies of interest. Table 2 shows the frequency response of numerous Bently Nevada vibration transducers along with notes regarding cable lengths. Obviously, as long as the field wiring provides a frequency response as good or better than the transducer itself, there will be no degradation of high-frequency content introduced by the field wiring. However, the total capacitance may exceed the allowable limits for hazardous area applications. Thus, when applicable, the designer must carefully consider both before deciding upon an allowable maximum cable length.

Table 2 – Field wiring and signal quality considerations for typical Bently Nevada transducers.

Transducer	Frequency Response	Notes
3300XL 8mm and NSv Proximitor* Sensor	0 – 10 kHz	Extended field wire lengths can attenuate relevant high-frequency content and affect measurement integrity.
3300XL 11 mm Proximitor Sensor	0 – 8 kHz	Extended field wire lengths can attenuate relevant high-frequency content and affect measurement integrity.
3300XL 25 mm Proximitor Sensor	0 – 2.7 kHz	Extended field wire lengths will rarely be an issue for frequency response considerations.
3300XL 50 mm Proximitor Sensor	0 – 50 Hz	Extended field wire lengths will rarely be an issue for frequency response considerations.
XL Radiation Resistant Proximitor Sensor	15 ft. system: 0 – 10 kHz 40 ft. system: 0 – 9 kHz 110 ft system: 0 – 5 kHz	Extended field wire lengths can attenuate relevant high-frequency content and affect measurement integrity.
LVDT	n/a	Extended field wiring lengths are not recommended under any circumstance due to the LVDT's sensitivity to resistance.
Velomitors	Varies depending on model. See pertinent transducer datasheet.	Extended field wire lengths can attenuate relevant high-frequency content and affect measurement integrity, depending on transducer frequency response.
Accelerometers	Varies depending on model. See pertinent transducer datasheet.	Extended field wire lengths can attenuate relevant high-frequency content and affect measurement integrity.
Thermocouples and RTDs	n/a	Extended field wiring lengths are not recommended under any circumstances due to the sensor's sensitivity to resistance.

The manual for each transducer will typically provide a graph similar to Figure 1, showing the affect of total cable capacitance on frequency response.

Figure 1 – Effect of field wiring total capacitance on frequency response for 3300 XL 8mm Proximity Transducer System (5 meter system length, no I.S. barriers)



Frequency Response Calculation Examples

Example 1

Goal

Determine the frequency response attenuation that will occur for a 3300 XL 8mm proximity transducer system (5 meter system length, no barriers) when 1500 m of GE's standard 18 AWG 3-conductor field wiring is used.

Solution

Using the value of 289 pF/m from Table 1 for 3-conductor field wiring, the total cable capacitance for 1500 m is found simply as:

289 pF/m x 1500 m = 433,500 pF = 433.5 nF

Since this value is very close to the 440 nF curve of Figure 1, we will use that curve for estimation purposes. When computing signal strength, it is customary to use the -3db point as the so-called cut-off frequency (–3dB represents a signal that has only one-half of the original amplitude). The –3dB point for 440nF of total field wiring capacitance is approximately 5 kHz. Thus, by introducing 1500 meters of field wiring, we have reduced the 10 kHz frequency response of the transducer system to approximately 5 kHz.

Example 2

Goal

Determine whether the transducer installation of example 1 would be acceptable for a speed-indication application using a 60-tooth wheel on a turbine running at 6200 rpm.

Solution

A proximity transducer observing a 60-tooth wheel turning at 6200 rpm will generated a square-wave type pulse with nominal frequency of:

60 teeth/rev x 1 pulse/tooth x 6200 rev/min = 372,000 pulses per min = 6200 pulses/sec = 6.2 kHz.

Clearly, the cable length introduces too much attenuation at this frequency, particularly since a "clean" square wave signal is necessary for a tachometer to trigger reliably. At this frequency (6200 Hz), even the fundamental (1X) component of the square wave will be attenuated by more than 4 dB as noted in Figure 1. The user would either need to shorten the field wiring length or choose field wiring with a lower capacitance-per-meter rating.

Hazardous Area Considerations

Another extremely important issue with extended length field wiring is the need to remain compliant with hazardous area classifications when applicable. Today, the most common methods of complying with hazardous area classifications are through the use of designs that are either intrinsically safe (in the case of Zone 0/1 areas) or nonincendive (in the case of Zone 2 areas). The principle behind such designs is to limit the amount of available energy such that a flammable atmosphere cannot be ignited under the appropriate conditions.

Nonincendive (N.I.)

The apparatus is incapable of releasing sufficient electrical or thermal energy under normal operating conditions to cause ignition of a specific flammable atmosphere.

Intrinsically Safe (I.S.)

The apparatus is incapable of releasing sufficient electrical or thermal energy under normal and abnormal operating conditions to cause ignition of a specific flammable atmosphere.

As can be seen, I.S. is a more stringent requirement, requiring a design that limits the energy under both normal and abnormal operating conditions. Consequently, designers will find that the maximum capacitance allowed for I.S. installations is more restrictive than for N.I. installations. Also, although both inductors and capacitors can store energy, the energy stored in the capacitance of the field wiring is much larger than that stored by the wiring's inductance for our transducer/monitor applications. Agency approvals work on the basis of "most restrictive." In other words, the designer looks at the cable lengths that will result in either excessive capacitive energy or excessive inductive energy, and uses the more restrictive constraint. Invariably, as noted, capacitance turns out to be the limiting factor for our applications. Consequently, the discussion here confines itself only to capacitance. However, be aware that with other electrical or electronic apparatus you encounter, inductance may be the limiting factor. The astute designer will know when an installation will need to be concerned with capacitive constraints instead of inductive constraints, and vice-versa.

I.S. installations rely on special current/voltage limiting devices, such as galvanic isolators or so-called I.S. barriers. Although each uses different principles of operation, the idea of an energy-limiting circuit is the same. When external barriers are used, a small voltage drop occurs across the resistance of the barrier. Bently Nevada monitoring systems designed for use with external barriers allow the user to compensate for this small voltage drop. Systems that are available with internal barriers, such as 3300 and 3500, provide this compensation automatically; it is transparent to the user.

When considering the allowable maximum length of field wiring, the designer consults the appropriate tables and specifications for the particular zone, atmosphere, and Bently Nevada hardware type, allowing the maximum capacitance available for field wiring to be determined. Once the maximum capacitance has been determined, the maximum field wiring length can be readily ascertained. Similar calculations are also performed to determine the maximum field wiring length while retaining the necessary frequency response for the application. Finally, the designer chooses the more restrictive of these two constraints (frequency response or hazardous area) and this becomes the governing criteria for the maximum cable length.

Several examples follow that demonstrate these concepts for typical monitoring system hardware.

[Editor's Note: Due to space limitations, only selected tables from the Applications Note have been provided here, allowing the reader to perform the sample calculations below.]

Hazardous Area Calculation Examples

Example 3

Goal

Determine the maximum cable length L_{max} allowed in a Zone 2 area with atmosphere type IIC for a channel using a 3500/42M monitor with Prox/Vel I/O module and a 3300 XL 8mm Proximity Probe (5 meter system length). Assume the use of field wiring with Bently Nevada part number 02120015.

Solution

Using Table 3, it can be seen that the maximum allowable connected capacitance C_o for a 3500/42 monitor with a Prox/Vel I/O module (p/n 140471-XX) is 0.2 µF (200 nF) regardless of atmosphere (gas) type. Next, per the published specifications in the 3300XL 8mm proximity transducer system datasheet, the input capacitance C_i of the Proximitor module is 5.7 nF, which we round off to 6 nF. This allows us to determine the maximum allowable total capacitance of the field wiring, C_{cable}, as follows:

$$C_{total} = C_{cable} + C_i \leq 0.2\mu F$$

$$C_{total} = C_{cable} + C_i \leq 200nF$$

$$C_{cable} + 6nF \leq 200nF$$

$$C_{cable} \leq 194nF$$

$$C_{cable} \leq 194{,}000pF$$

Now, since we have found the maximum total cable capacitance C_{cable}, the maximum allowable length is simply C_{cable} divided by the capacitance per unit length (which is found in Table 1):

$$L_{max} = \frac{C_{cable}}{289pF/m} = \frac{194{,}000pF}{289pF/m}$$

$$L_{max} = 671m$$

It is worth noting that while up to 671 m of this field wiring would allow the system to remain within hazardous area constraints, it introduces 194 nF of total capacitance which affects the frequency response adversely. Referring again to Figure 1 (we will use the curve for 176 nF since it is close to the actual value of 194 nF), it can be seen that the -3dB point is now less than 10 kHz (somewhere between 8 and 8.5 kHz). Thus, for applications that require the full 10 kHz frequency response of the proximity transducer, the field wiring would have to be shortened until the attenuation was within acceptable limits.

Project Services

Although many customers will feel comfortable performing these calculations themselves and managing the installation of transducers, monitors, and associated field wiring, other customers prefer to use GE's project services capabilities. These services can be provided for selected portions of a project, such as field wiring calculations; or, they can be provided as part of a broader scope, such as preparation of drawings, supervision of subcontractors, and field machining services to retrofit or upgrade instrumentation on existing machinery.

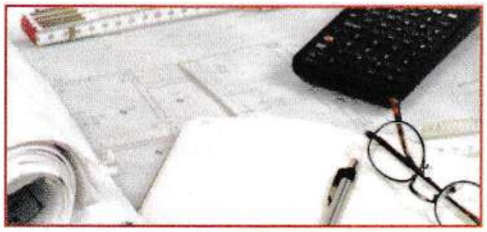


Table 3 – Maximum capacitance for 3500 monitoring system I/O modules in Zone 2 hazardous areas for gas group IIA - IIC

Module Number	Co by gas group (uF)		
	IIC	IIB	IIA
146031-01, 3500/22M-01	1000		
140471-01,-02 3500/25, 3500/4x Prox / Velomitor 3500/64	0.2		
169459-01, -02, 350 0/4x Multimode, Prox/Velom (IT and ET)	0.2		
169715-01, -02, 3500/4x, Multimode Positive Input (IT and ET)	0.1		
125800-01, 3500/25	0.2		
133819-02, 3500/61, Thermocouple and RTD	1.56	10.5	42
133835-02, 3500/61, Isolated Thermocouple	1.56	10.5	42
136491-01, 3500/62, +/- 10Vdc I/O	1.71	1.71	48

Example 4

Goal

Assume the details given in example 3; however, installation constraints now require that the transducer system be located a minimum of 1000m from the monitor system. Find the maximum cable capacitance per unit length that can be used.

Solution

The maximum total cable capacitance C_{cable} is the same as in example 3; namely, 194,000 pF. Here, however, we are given the length and need to find the capacitance per unit length C_{UL}.

$$L_{max} = \frac{C_{cable}}{C_{UL}} \qquad C_{UL} = \frac{194{,}000\text{pF}}{1000\text{m}}$$

$$C_{UL} = \frac{C_{cable}}{L_{max}} \qquad C_{UL} = 194\text{pF/m}$$

Thus, field wiring cable should be chosen with a capacitance per unit length less than or equal to 194 pF/m. Since this value is less than the standard 18 AWG 3-conducter field wiring cable of Table 1, GE's standard cable cannot be used and an alternative cable type meeting the required capacitance per unit length must be employed.

As pointed out in example 3, although the length of field wiring used here will allow the system to remain within the constraints imposed by the hazardous area criteria, it will result in some roll-off of the frequency response. As such, this length of field wiring may or may not be acceptable depending on whether the full 10 kHz frequency response available from the proximity transducer is required or not.

Example 5

Goal

Determine the maximum cable length L_{max} for the channel described in Example 3 except now it must be suitable for a Zone 0 classified area with gas group IIC. Assume that the 3500 monitor uses an I/O module for Prox/Accel with internal barriers. Assume also the same field wiring type as example 3.

Solution

Using Table 4, it can be seen that the maximum allowable connected capacitance C_o for a 3500/42 monitor with an internal barrier Prox/Vel I/O module (p/n 135470-01) is 0.083µF (83 nF). Also, as before, the input capacitance Ci of the Proximitor module is approximately 6 nF. This allows us to determine the maximum allowable total capacitance of the field wiring, C_{cable}, as follows.

Table 4 – Maximum capacitance for 3500 monitoring system I/O modules in Zone 0/1 hazardous areas with gas group IIC atmospheres

Barrier Module Number	C_o by gas group (uF)
135470-01, Proximitor & Accelerometer	0.083
135471-01, Velomitor	0.088
137101-01, Process Variable	0.76
135472-01, Temperature	8.8

$$C_{total} = C_{cable} + C_i \leq 0.083\mu F$$

$$C_{total} = C_{cable} + C_i \leq 83nF$$

$$C_{cable} + 6nF \leq 83nF$$

$$C_{cable} \leq 77nF$$

$$C_{cable} \leq 77{,}000pF$$

Finally, the maximum allowable length is found using the same equation as 3.

$$L_{max} = \frac{C_{cable}}{289pF/m} = \frac{77{,}000pF}{289pF/m}$$

$$L_{max} = 266m$$

Summary

Long field wiring lengths are sometimes required due to the nature of the cable runs and plant layout. This introduces additional capacitance and can affect the integrity of the monitoring system in one or both of the following ways:

- By attenuating high frequencies in the vibration signal
- By allowing too much stored electrical energy, violating hazardous area certification limits

In order to determine the maximum length of field wiring, the designer must therefore understand both the necessary frequency response required by the application and the allowable maximum capacitance for the particular hazardous area classification (when applicable). The calculations allow the designer to determine either the maximum length of standard field wiring cable that can be used, or the maximum capacitance per unit length of alternate field wiring, allowing cable with appropriate specifications to be procured.

MDS – At Your Service

Approximately 22 years ago, I departed a VP position at Bently Nevada Corporation to establish my own machinery consulting business. Since that time, I have solved some fascinating problems, expanded my knowledge of machinery characteristics, developed proficiency in the analytical modeling of rotor systems, and published the book: *Machinery Malfunction Diagnosis and Correction—Vibration Analysis and Troubleshooting for the Process Industries.*

With my return earlier this year to the role of Global Machinery Diagnostics Services Manager after more than two decades, I've come full circle. While I have found that some things have changed (such as the ownership and the name—we're now GE Energy), many things have remained constant. Specifically, the desire to provide exceptional customer service, the professional level and dedication of the Bently Nevada Machinery Diagnostic Services (MDS) personnel, and the overall commitment to quality and integrity are all alive and well. These are fundamental concepts that form the foundation of our machinery consulting business, and I fully expect these concepts to perpetuate into the future. In terms of physical changes during the past two decades, I have discovered that the handful of MDS engineers on board in 1985 has expanded to over 100 MDS engineers world-wide as of this writing. Some of these engineers have basic knowledge, and others have multiple decades of direct field experience. Clearly this diverse personnel base provides some major challenges in terms of technical training and professional development. I expect that this requirement will consume a significant amount of my time in the months and years to follow. In fact, I consider it a mandatory obligation to pass along the lessons and experiences of my career to the next generation of machinery engineers.

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It is clear that providing high-level machinery diagnostics often requires more than an evaluation of shaft vibration characteristics. In this regard, we plan to pursue and incorporate additional transducers and measurement technologies. This includes measurement of Operating Deflection Shapes (ODS), plus natural frequencies and mode shapes of machinery elements and structures. In addition, we will provide measurements of free-free bending modes of turbomachinery rotors. These additional measurements will be supplemented with a substantial expansion of our analytical software capabilities to provide enhanced computation and evaluation of lateral and torsional rotor systems. This combination of measurements and calculations will be integrated with expanded training and understanding of machinery components, assembly details, and unit operational characteristics.

"WITH MY RETURN EARLIER THIS YEAR TO THE ROLE OF GLOBAL MACHINERY DIAGNOSTICS SERVICES MANAGER AFTER MORE THAN TWO DECADES, I'VE COME FULL CIRCLE."

The net result of these expansions in technology and investments in personnel will be a significant increase in our overall ability to accurately identify problems and recommend corrective solutions. It is anticipated that these enhancements will position MDS as the most cost-effective supplier of multiple levels of machinery consulting services. These services will be available for virtually any type or manufacturer of machinery, they will be available around the world, and increasingly they will be available remotely via network connectivity. In future issues of ORBIT, I'll be providing specific details of these global enhancements to our MDS offerings. For now, I'll simply introduce myself, let you know it is good to be back, and that I'm very optimistic about our current capabilities and our ability to meet the future needs of our customers.

Beat Frequencies

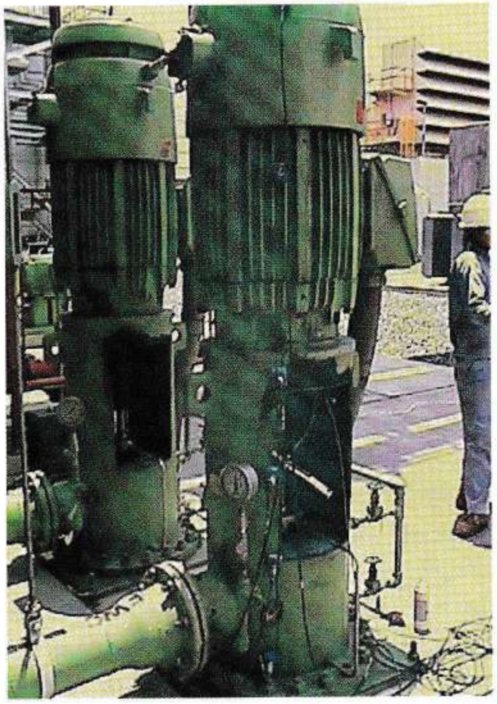
Beating occurs when there are two dynamic excitation sources (forces) very close together in frequency and a pathway allowing the two excitation forces to transfer to one another. The so-called "beating effect" results because the frequencies are so close to one another that the waveforms alternately reinforce one another at some times and cancel one another at other times. During times when the vibration from each source adds constructively, the vibration increases; during times when the vibration adds destructively, the vibration decreases.

An example of this occurred when the author was diagnosing two condensate pumps (Figure 1), located side by side and running at almost exactly the same rotational speeds. The prime movers for the pumps were induction motors where slight differences in speed will always be present as a function of how much slip occurs under varying load conditions. The residual unbalance in the pumps gave rise to fairly large excitation forces. Also, the piping and mounting details provided the necessary mechanical transmission path for the vibration from each pump to affect the other.

Figure 2 shows the resulting vibration trend when both pumps were running simultaneously. Note that at the tail end of Figure 2, when the second pump had been stopped, the beat effect ceased and the vibration consequently assumed a stable trend.

Another machine type in which beating can be common is the centrifuge (Figure 3), where the bowl and screw rotate with slightly different speeds.

Figure 1 – Side-by-side condensate pumps. Piping and mounting details allowed vibration from one pump to significantly affect the other, particularly when the residual unbalance forces were high.



When sufficiently large excitation forces exist, which is often the case with centrifuges due to build-up of material and subsequent unbalance, beating can occur. The beat frequency may arise from either the differences in speed between the bowl and the screw, or between the rotating fluid and the bowl.

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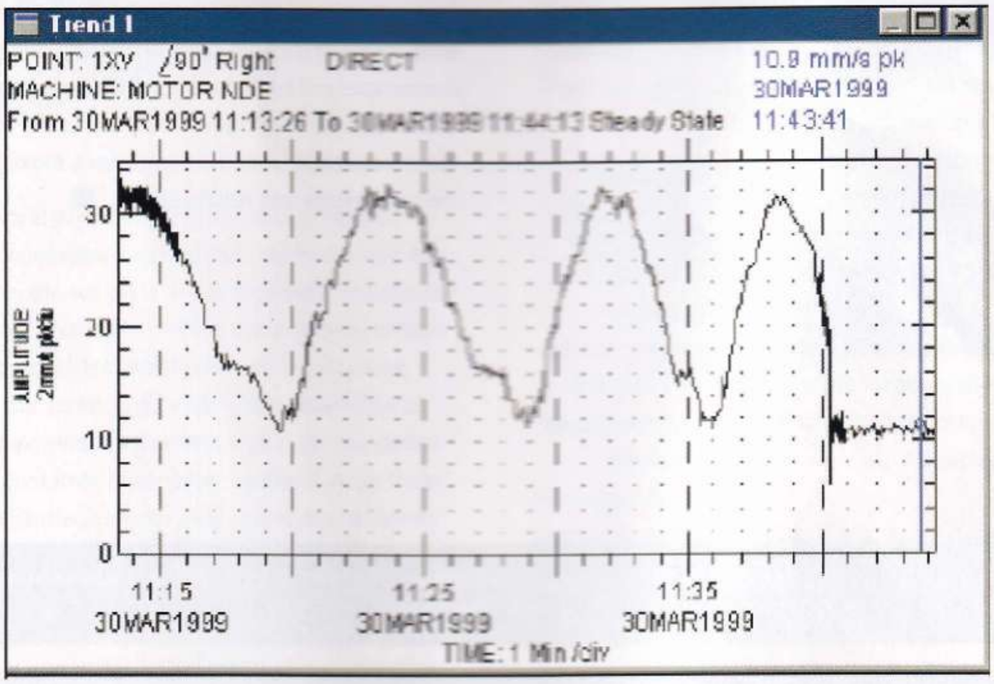
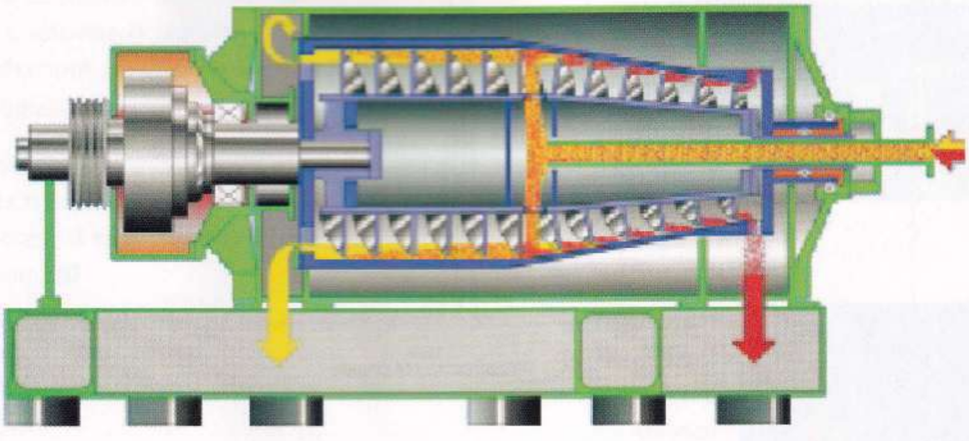
Figure 2 – Amplitude modulation on condensate pump of Figure 2, arising due to beating effect. Note that vibration trend becomes steady at the tail end of the plot, after the second pump has been turned off.



Trend 1

POINT: 1XY /90° Right DIRECT 10.9 mm/s pk
MACHINE: MOTOR NDE 30MAR1999
From 30MAR1999 11:13:26 To 30MAR1999 11:44:13 Steady State 11:43:41

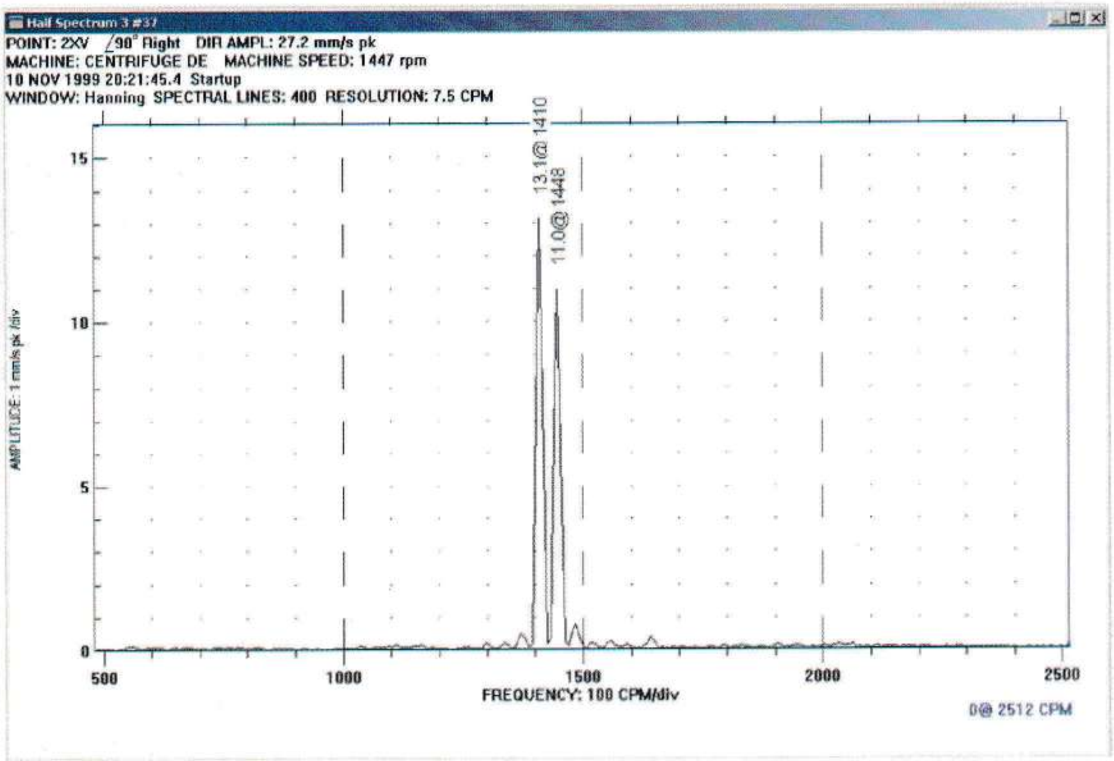
Figure 3 – Cross-sectional view of centrifuge machine showing two main rotating parts (bowl and screw) with slightly different in speed (image courtesy of TEMA/Seibtechnik).



To ascertain whether beating frequencies are present, the simplest method is the use of a high-resolution spectrum plot, as shown in Figure 4. Clearly, the sampling frequency must be chosen to give sufficient resolution between spectral components and prevent so-called spectral "smearing" from occurring. For the example of Figure 4, the data was collected from a centrifuge and the two frequencies differ by 38 rpm as can be noted by the amplitude/speed labels at the top of the two predominant spectral peaks. Because the resolution has been set for 7.5 cpm (0.125 Hz), it can easily distinguish between these two spectral components which are 38 rpm apart. However, had the frequencies been closer together (such as 1 or 2 rpm apart), a spectral resolution of 0.016 Hz or better would have been required.

When performing field or shop balancing on machines in which a beat effect is present, it is likewise important to configure instrumentation with suitably sharp filter roll-off so that only the spectral component of exact running speed (1X) will be present and all other frequencies will be filtered out. Otherwise, the phase and amplitude readings will be distorted by the adjacent "beat frequency" spectral component, making balance measurements and results erratic.

Figure 4 – Spectrum showing two frequencies very close to one another (38 rpm apart). The beat frequency is the difference between these two frequencies; in this case 38 rpm or 0.63 Hz.



Half Spectrum 3 #37

POINT: 2XV ∠90° Right DIR AMPL: 27.2 mm/s pk
MACHINE: CENTRIFUGE DE MACHINE SPEED: 1447 rpm
10 NOV 1999 20:21:45.4 Startup
WINDOW: Hanning SPECTRAL LINES: 400 RESOLUTION: 7.5 CPM

Customer Application Centers

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